Duke Energy Ohio Smart Grid Audit and Assessment

June 30, 2011

Prepared for:
The Staff of the Public Utilities Commission of Ohio
PUBIC VERSION WITH CONFIDENTIAL INFORMATION REDACTED

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Creating a Return on Environment

Prepared by:
MetaVu, Inc.
2240 Blake Street, Suite 200
Denver, Colorado 80205 USA
+1 (303) 679-8340
www.metavu.com

PREFACE

The U.S. electric distribution grid is considered by many to be the largest machine ever built. Despite its size, the distribution grid has limitations that will likely be tested soon. Today's grid incorporates the same basic designs of grids constructed 100 years ago. It was designed to reliably distribute electricity uni-directionally, from generators to customers, in a manner that optimized capital investment and operating costs. In the future electric customers will likely expect new capabilities, and the distribution grid must be prepared to deliver. New demands are likely to include:

- Bi-directional power flow (large numbers of customers generating as well as using electricity).
- Advanced pricing plans (providing customers with cost management opportunities).
- Higher distribution energy efficiency (minimizing line losses).
- Improved customer service levels and new services.
- Ability to accommodate large numbers of electric vehicles.

Grid operators are also likely to require new services to facilitate management of many new objectives at the lowest possible cost, including:

- Maintenance or improvement of reliability in the face of new demands.
- Reliable incorporation of intermittent renewable generation sources.
- Improved utilization of generation, transmission, and distribution system capacity.

Duke Energy (and in particular Duke Energy Ohio) was among the first utilities to propose making significant investments to prepare its distribution grid for future demands through the use of advanced monitoring, information and communications technologies (the 'smart' grid). The Public Utilities Commission of Ohio (Commission) was among the first public utility commissions to approve a full smart grid deployment, and was also among the first to authorize its staff to conduct an audit and assessment of the deployment and of economic benefits delivered.

This report details the results of the authorized audit and assessment, as conducted by MetaVu, Inc. (MetaVu) under the direction of the Staff of the Public Utilities Commission of Ohio (Staff) from January to June, 2011. MetaVu employed the services of specialty project partners Alliance Calibration, Inc. (Alliance Calibration) and OKIOK Data, Ltd. (OKIOK) to complete the audit and assessment and prepare this report. The intended audiences for the report include the Commission, Duke Energy, various stakeholders that are generally parties to Duke Energy Ohio regulatory proceedings and the people of the state of Ohio.

MetaVu would like to thank the management and employees of Staff, project partners, and Duke Energy, without whom the audit and assessment could not have been successfully completed.

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About MetaVu

MetaVu is a recognized leader in sustainable business development, delivering the solutions companies need to innovate products, services and business models to manage energy, social and environmental risk throughout the value chain. In the utility sector, MetaVu helps clients integrate customer, technology and regulatory strategies into profit-generating products and business models including demand side management, renewable energy development, and smart grid evaluation and deployment.

Disclaimer

MetaVu served as a Staff resource for the Audit and Assessment described in this report and used best efforts to collect and analyze relevant information from Duke Energy. Report users should consider that the veracity and precision of Audit and Assessment findings are based on representations provided by Duke Energy. MetaVu recommends that experienced professional advisors be consulted in the event the information herein is intended to be used for a particular purpose.
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1 EXECUTIVE SUMMARY

This report documents the results of a mid-deployment audit and assessment of the Duke Energy Ohio grid modernization project by the Staff of the Public Utilities Commission of Ohio (Staff). Duke Energy Ohio agreed to a mid-deployment audit and assessment as part of regulatory proceedings associated with the Duke Energy Ohio Electric Security Plan Case No. 08-920-EL-SSO. Staff selected MetaVu, Inc. (MetaVu) to support Staff's audit and assessment through a competitive bidding process.

The purpose of the audit and assessment was to verify and quantify the value of smart grid deployment to Duke Energy Ohio customers and to identify any appropriate changes or revisions to the smart grid deployment plan. The audit and assessment was structured into several sub-components including:

- An Operational Audit
- A Systems Integration Assessment
- A Guidelines and Practices Conformity Assessment
- An Operational Benefits Assessment

1.1 Audit and Assessment Background

On July 31, 2008, Duke Energy Ohio filed an application for approval of an Electric Security Plan (ESP), Case No. 08-920-EL-SSO. The application included a business case for the deployment of a smart grid in Duke Energy's Ohio service territory. Many of the parties in the Duke ESP Case entered into a stipulation that provided for the implementation of smart grid technologies, established a rider for the recovery of smart grid deployment costs, and called for a mid-deployment review of progress in the second quarter of 2011. The Commission issued an opinion and order approving the stipulation on December 17, 2008.

The stipulation required Duke Energy Ohio to file applications in the second quarter of each year to recover smart grid expenditures from the previous year. The stipulation entered into as part of Duke Energy Ohio's application (09-543-GE-UNC) to recover 2009 smart grid costs, approved by the Commission on May 13, 2010, stated in pertinent part:

> *"In order to provide Staff and interested stakeholders ample opportunity to verify and ensure value to customers, and in preparation for the midterm review Duke Energy Ohio will provide Staff with such data and information as may be necessary to understand any revisions or changes to its business case for Smart Grid as set forth in Case No. 08-920-EL-SSO including information pertaining to revised projected costs, and revised projected operational benefits for the period of the business case. Duke Energy Ohio commits to provide such information prior to the midterm review described in Case No. 08-920-EL-SSO."*

Staff developed and issued a Request for Proposal EE10-OA-1 that solicited support to conduct the Audit and Assessment authorized by the Commission. MetaVu and its project partners were awarded the bid after a competitive solicitation process. The scope of the Audit and Assessment is described below.

1.2 Audit and Assessment Scope

Staff developed an Audit and Assessment Scope that guided MetaVu's project planning and execution efforts and those of its project partners. The Audit and Assessment scope included an Operational Audit, a Systems Integration Assessment, a Guidelines and Practices Conformity Assessment, and an Operational Benefits Assessment as described below.

Operational Audit

The Operational Audit consisted of a review of installed equipment and systems, an analysis of their functionality, and a mapping of deployment status against implementation plans. Operational Audit activities included:

- A field audit of Duke Energy Ohio's smart grid deployment to date
- An analysis of the degree to which deployed components function as they should (e.g., are the smart meters accurate)
- A comparison of deployment status to date with overall deployment plans and a determination of the extent of deployment remaining for completion

Systems Integration Assessment

The Systems Integration Assessment consisted of an analysis of the degree to which smart grid components work together with other components and systems. Systems Integration Assessment activities included:

- An analysis of the degree to which components deployed are systemically integrated with one another, including communications from meters through the creation of customers' bills
- A test of the accuracy of billed data for customers participating in time-differentiated pricing pilots
- An analysis of the degree to which deployed components are integrated with other Duke Energy Ohio business systems such as outage management, work force deployment, asset management, and other information systems

Guidelines and Practices Conformity Assessment

The Guidelines and Practices Conformity Assessment focused on how, and the degree to which, Duke Energy Ohio's smart grid systems and their deployment conform with emerging guidelines and best practices. The Guidelines and Practices Conformity Assessment included:

- A review of the guidelines development process ongoing at the National Institute of Standards and Technology (NIST)
- An assessment of conformity with evolving guidelines
- The identification of potential risks of non-conformity and the implications of such risks
- The identification of best practices and characterization of Duke Energy Ohio practices in that context
- The identification of practices that pose significant risks associated with having to fix or redeploy components and systems

Operational Benefits Assessment

The Operational Benefits Assessment focused on estimating the net present value of benefits to Duke Energy Ohio resulting from smart grid deployment. The activities included:

- An assessment of 23 Operational Benefits included in Duke Energy Ohio's smart grid business case including those anticipated to reduce operations and maintenance costs, increase revenue, avoid fuel costs, or defer capital expenditures
- The identification of two Operational Benefits that Duke Energy Ohio did not include in its smart grid business case
- An estimation of the dollar value and timing (net present value) of the 25 Operational Benefits

The scope of work did not include any estimation or valuation of customer or societal benefits attributable to smart grid deployment nor did it include a financial audit for cost recovery purposes. The overall objective was to assist Staff in examining Duke Energy Ohio's smart grid deployment to date and its business case on a going-forward basis, and to document those findings for the record in Case No. 08-920-EL-SSO.

1.3 Audit and Assessment Findings

MetaVu facilitated the inquiry, assessment and analysis phase of the Audit and Assessment through collaboration with subject and domain experts of project partners and Staff. The resulting analysis is documented in the following sections:

Operational Audit Findings

Meter Tests

- A test of a statistically significant number of smart electric meters revealed that the smart meters' measurement accuracy is well within manufacturer's specifications and better than the traditional meters they are replacing.
- A test of gas meter data transmitters revealed that they accurately communicate gas meter readings to Duke Energy Ohio meter data management systems.
- A test of gas meter data transmitters' Radio Frequency (RF) emissions indicated field strengths within FCC guidelines and lower than many electric devices commonly used by consumers.

Field Equipment Audit

As of December 31, 2010:

- Smart meter deployments were found to be 46% complete compared to a planned deployment of 85%, with corresponding delays of associated Operational Benefits.
- The installation of 'smart' equipment intended to reduce outage extent (the number of customers impacted by an average outage) is on schedule with approximately 60% remaining to complete.
- The installation of 'smart' equipment in Duke Energy Ohio's Cincinnati substations is slightly behind plan with 69% remaining to complete.
- The economic benefits of 'smart' equipment intended to improve electric distribution efficiency is largely dependent on software, with completion anticipated in 2013.
- A comparison of readings displayed on devices in the field to data available in Duke Energy Ohio's Electric Management System and historical data repository revealed no significant differences, indicating that all installed equipment was functioning as intended when inspected.

Systems Integration Assessment Findings

The Systems Integration Assessment found:

- Usage data from 47 smart electric meters and 47 gas meters equipped with wireless data transmitters was traced through communication infrastructures and a number of Duke Energy data processing systems used to generate customer bills. No data integrity issues were identified, indicating that systems used to communicate and manage billing data are adequately integrated.
- Bills from a randomly selected sample of customers on time-differentiated rates (12 on rate TDAM and 13 on rate TDLITE) were audited from source energy usage data collected in 15 minute intervals. No errors in the calculation of customer bills were found.
- A review of the usage data Validation, Editing, and Estimation (VEE) routines utilized by the two data processing systems (EDMS and MDMS) used to prepare usage data for customer bill generation, including those used to prepare time-differentiated rate bills, found that they were adequate to identify errant billing data and functioning properly at the time they were inspected.
- MetaVu reviewed the capability of Duke Energy Ohio's Advanced Metering Infrastructure (AMI) to measure MAIFI (Momentary Average Interruption Frequency Index) as defined by the IEEE (Institute of Electrical and Electronics Engineers). MetaVu's review concluded that there is no readily available approach to measuring MAIFI as defined by the IEEE from existing AMI capabilities, although some reasonable approximations could be made available with significant effort and cost.
- MetaVu reviewed the planned integration of the yet-to-be-deployed Distribution Management System (DMS) that Duke Energy Ohio intends to use as the centerpiece of distribution

automation. MetaVu found that detailed plans and budgets for completing extensive integration of the DMS with existing systems, including SCADA, Outage Management, Workforce Management, data historian, are in place. MetaVu recommends that a thorough and formal change management plan be designed and executed as part of the DMS implementation to maximize DMS value.

- MetaVu also reviewed business process integration as part of the Systems Integration Assessment and found several opportunities to make better use of meter data including:
  - Use of meter status to proactively detect smaller and localized outages
  - Use of meter power quality data to improve voltage monitoring capabilities
  - Use of meter data for capacity planning purposes
  - Use of meter data to enhance customer DSM program effectiveness (such Power Manager®)
- Though outside Duke Energy Ohio's deployment plan scope, MetaVu noted opportunities to incorporate advanced substation monitoring and reporting as part of a future phase of smart grid development.

Guidelines and Practices Conformity Assessment Findings

The Assessment of Conformity with Guidelines and Practices found:

- The NIST guidelines against which Duke Energy Ohio's smart grid was evaluated are a superset from which utilities are expected to select as applicable. As such, utilities are not expected to comply with the complete set of requirements defined in the NIST guidelines.
- Instances of low conformity with NIST guidelines does not necessarily imply that Duke Energy does not have valid security practices in place, only that they do not meet some of the very specific requirements called for in the NIST guidelines.
- Duke Energy was found to be in full or partial conformity with five of the "families" of the NIST guidelines but was found to conform to less than half of the requirements of four other families of guidelines.

[redacted]

- [redacted].
- Some families were identified as both non-conforming and associated with a high potentiality of a security breach.
- [redacted]
- The Duke Energy Personal Information Privacy Policy describes the requirements for protecting the privacy of personal information but does not explicitly protect energy data collected and processed by smart grid information systems.
- Electric smart meters [redacted]:
  - [redacted]
  - [redacted]
- Gas meter data transmitters [redacted]

[redacted].

- Electric smart meters [redacted]

Operational Benefits Assessment Findings

MetaVu estimated the Net Present Value (NPV) of Operational Benefits available from Duke Energy Ohio's smart grid deployment at $382.8 million in the base case with a low case of $325.8 million and a high case of $447.5 million. Summary findings are provided below:

- About 90% of the benefits can be traced to two smart grid capabilities: Advanced Metering Infrastructure (AMI) and Integrated Voltage/VAR Control (IVVC).
- Operations and Maintenance costs avoided from the implementation of AMI represent about 45% of the total benefits and include avoided labor and vehicles costs from remote meter reading and diagnostic capabilities (the vast majority), as well as improved meter accuracy and power theft detection (which increase billed sales volumes).
- Fuel (and purchased power) costs avoided from IVVC capabilities represent another 45% of the total benefits. Improved control of Voltage and VAR increases the efficiency of the distribution grid and therefore the amount of power delivered to customers per unit of power generated.
- Though a variety of grid capabilities combine to help defer capital investments, this type of value is smaller than the others analyzed (Avoided Operations and Maintenance Costs, Avoided Fuel Costs, and Increased Revenues). This is particularly true when one considers that customers realize the value of deferred capital over long periods of time.
- The most significant drivers of smart grid benefit NPV include assumptions about:
  - Cost growth rates
  - Software and hardware deployment rates
  - Projected distribution grid performance improvements post deployment
  - Impact of automation on labor and capital
  - Discount rate

1.4 Report Organization

This report is organized into four Sections, one for each of the primary scopes. Each Section follows the following outline:

- An **Introduction** that provides background and general information on the specific audit or assessment
- A description of the **Methodologies** used to complete the specific audit or assessment
- **Findings** for detailed components examined within the specific audit or assessment

In addition, an extensive **Appendix** includes details and clarifications that were segregated to ensure smooth presentation of report content.

2 OPERATIONAL AUDIT

2.1 Introduction

The Staff of the Public Utilities Commission of Ohio (Staff) asked MetaVu and Alliance Calibration[1] to conduct an operational audit of installed smart grid equipment and systems and an analysis of their functionality. The Operational Audit was conducted to answer two primary questions:

1. Are deployed components of the smart grid functioning as they should?
2. What is the deployment status relative to completion as defined by original implementation plans?

The Operational Audit was prompted in part by concerns about meter accuracy and health impacts by electric customers in Texas and California. MetaVu executed the Operational Audit with the assistance of Cincinnati-based Alliance Calibration through three primary means:

1. Lab-testing of samples of smart electric meters, gas meter wireless data transmitters, and traditional electric meters.
2. Review and observation of meter lot testing and installation procedures.
3. Field audits of a sample of smart grid equipment installed throughout Duke Energy's Ohio distribution grid.

[1] Alliance Calibration is an ISO/IEC 17025:2005 accredited laboratory with staffers credentialed by the American Society of Quality in Calibration Technology. Alliance Calibration staffers also hold certifications as Internal Auditors for ISO/IEC 17025 and in measurement uncertainty training.

Alliance Calibration employed a purpose-built environmental chamber to test electric meters under a variety of simulated weather conditions. Gas meter data transmitters were tested in a semi-Anechoic Radio Frequency Chamber to test RF emissions. The lab tests and field audit also afforded opportunities to inform other aspects of the assessment (Systems Integration, Guidelines and Practices, and Operational Benefits).

This Introduction concludes with diagrams that illustrate the physical layouts of Duke Energy Ohio's Advanced Metering Infrastructure (AMI) and Distribution Automation (DA) system. The balance of the Operational Audit section includes descriptions of audit methodologies and is followed by audit findings organized into Metering and Distribution Automation components:

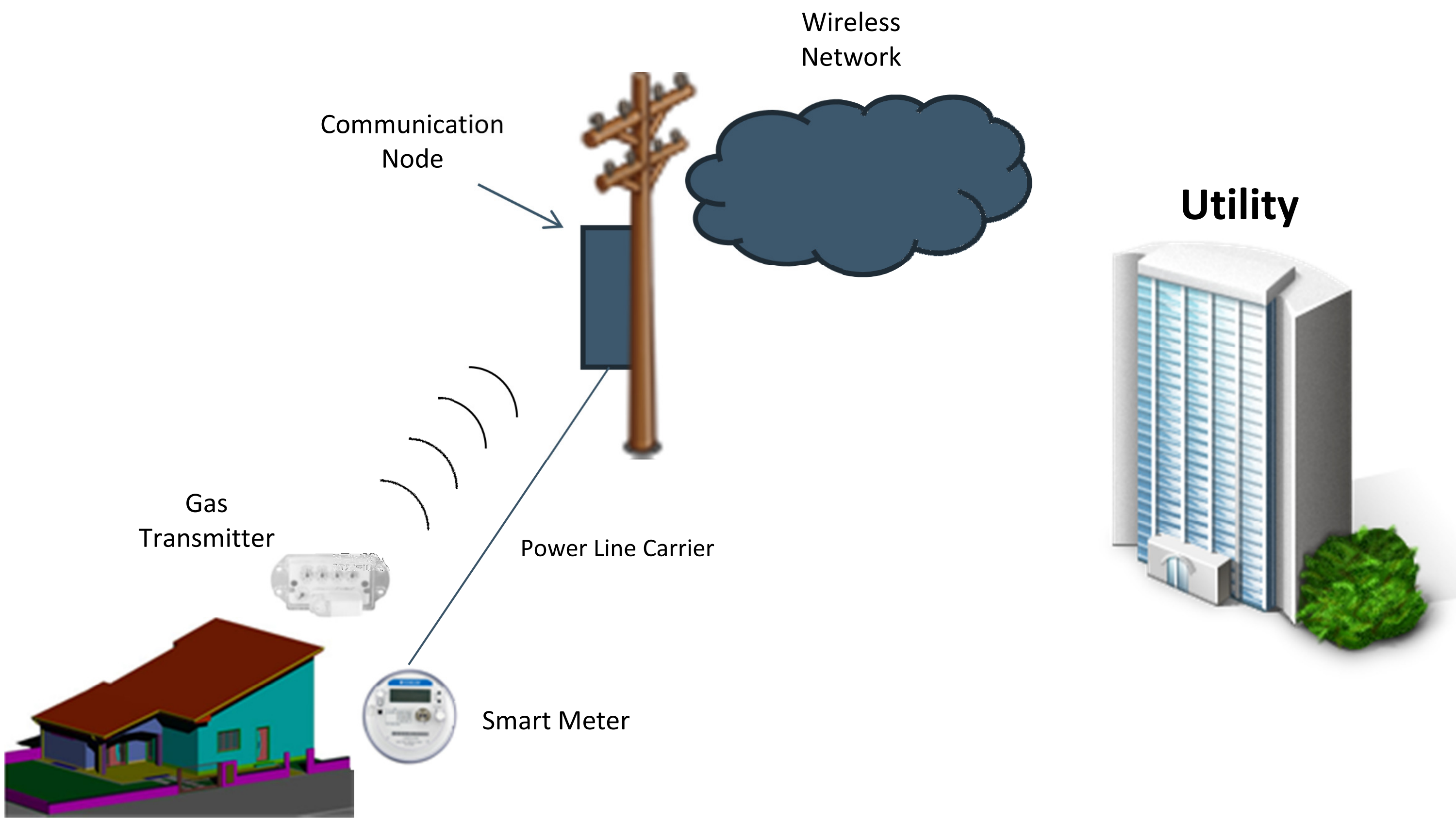
Metering Audit

- Tests of smart electric meters
- Tests of traditional electric meters
- Tests of gas meter wireless data transmitters
- Review and observation of meter installation and meter lot testing procedures

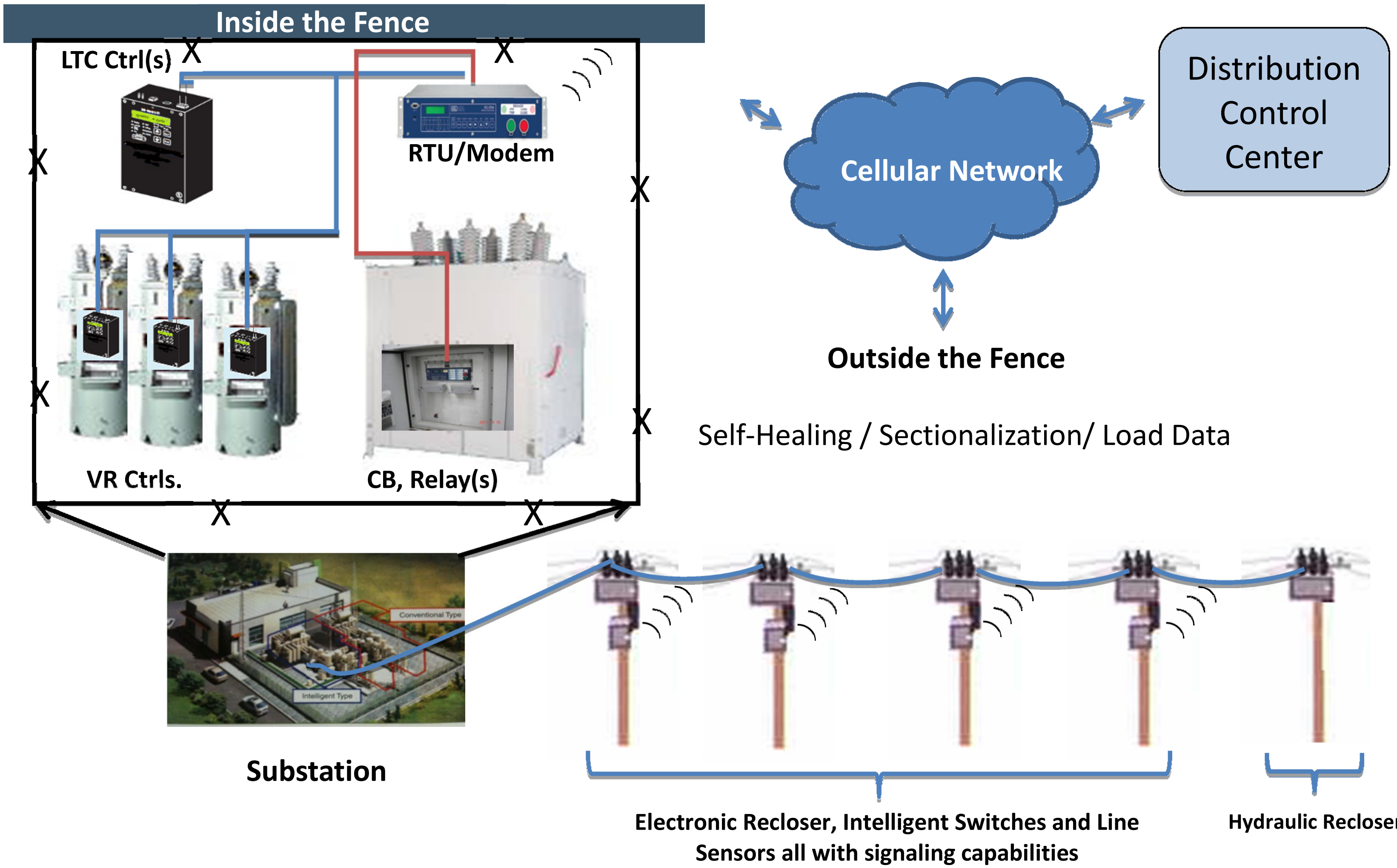
Distribution Automation Audit

- Substations
- Feeders/Laterals

The following diagram illustrates the AMI architecture of Duke Energy Ohio. As exemplified below, electric smart meters and gas meter transmitters send data to communication nodes located throughout the smart meter service area. Those communication nodes then transmit customer data to the utility for analysis.



The diagram below depicts architecture of the Distribution Automation (DA) system of Duke Energy Ohio. Within the fence of the substation, load tap changer controllers, voltage regulator controls, circuit breakers, relays, and Remote Terminal Units (RTU) automate the substation and communicate critical data to the utility. On the distribution line, various reclosers and recloser controllers, intelligent switches, and other devices work automatically to improve grid state operations.



2.2 Methodologies

MetaVu and Alliance Calibration were careful to create and document measurement methodologies appropriate to achieve the goals of the Operational Audit. Measurement methodology overviews are provided below for:

- Electric Meter Tests
- Gas Meter Data Transmitter Tests
- Distribution Automation Equipment Audits

Additional test details are available in Appendix 1: Meter Test Inspection.

Electric Meter Tests – Standards and Procedures

Electric Meter Tests included tests of smart meters in-service for at least 90 days, tests of inventoried smart meters not yet deployed in the field, and tests of traditional meters. Tests consisted of meter accuracy under a variety of weather conditions and loads. Initially, it was anticipated 48 smart meters in-service for 90 days would be tested but the inability to access one customer premise precluded testing of one smart meter. The tests for inventoried (not yet placed into service) smart meters and traditional meters included 48 meters of each type.

The meter under test is then read by the tester to determine the meter's accuracy compared to the standard. The testing device used was the TransData 2130 which allows for the testing of various types of electrical meters (electromechanical, digital and smart) with an internal accuracy standard of ±0.025% (a far higher accuracy rate than the meters tested). For more information see Appendix 1-A: Electric Meter Test Plan.

Electrical meters were tested with a variety of known loads that are typical of consumer usage. Meters were tested at ambient room temperature, at -40^{o}C, and +40^{o}C (temperatures recommended according to American National Standards Institute (ANSI) standards). Traditional meters consisting of both mechanical and digital types from 6 different manufacturers were tested along with the smart meters.

The testing of electric meter measurement accuracy is a mature field governed by process and quality standards set by several recognized organizations. The National Institute of Standards and Technology, commonly referred to as NIST, is one such organization. NIST is a non-regulatory federal agency with a mission to promote U.S. innovation and industrial competitiveness by advancing measurement science, standards, and technology. The calibration of the test equipment utilized in the electric meter test is traceable to NIST.

A second relevant standard-setting body is the American National Standards Institute which governs the creation, use, and ongoing development of thousands of norms and guidelines. ANSI is also actively engaged in accrediting programs that assess conformance to standards – including globally-recognized, cross-sector programs such as the International Organization for Standardization or ISO 9000 (quality) and ISO 14000 (environmental) management systems. The methods used to test electric meters were in compliance with the C: 12.20-2010 American National Standard for Electricity Meters 0.2 and 0.5 Accuracy Classes.

The International Organization for Standardization is the world's largest developer and publisher of "International Standards" and serves as a network of the national standards institutes of 160 countries**.** Alliance Calibration is accredited to ISO/IEC 17025:2005 by the Laboratory Accreditation Bureau.

Electrical Meter Tests – Sampling and Statistical Significance

The mathematical field of statistics governs the process of "sampling." Properly applied, statistical principles can be used to evaluate and describe the degree to which the results of a sample can be assumed to represent the results of an entire population. Factors that determine the size of a statistically significant sample include:

- What is the failure rate for the devices being tested?
- What is the accuracy of the testing equipment relative to the devices being tested?
- What is the desired degree of confidence that the sample results reflect those of the entire population?

- What is the performance variability (margin of error) of the devices being tested?
- What is the size of the population?
- Are the meters being tested a representative (i.e., randomly selected) sample of the population?

Assumptions used to determine the appropriate sample size for Electrical Meter Tests include:

- Failure rate = 0.15%
- Smart Meter manufacturer stated accuracy of ± 0.5% from -40^{o}C to + 85^{o}C
- Traditional meter regulated minimum accuracy of ± 2.0%
- Testing equipment accuracy of ±0.05%
- Confidence level and confidence interval is set such that there is 95% confidence that the population results would be within ±5.0% of the sample results
- Device performance variability (margin of error) is 1%
- The total population of devices is greater than 20,000
- Meters to be tested were selected at random

Based on the above data a sample size of 58 meters was calculated as the minimum acceptable to ensure statistically significant results. In fact, 95 smart meters were tested so that there could be no doubt about the statistical validity of the results. The 95 smart meters tested included 47 in-service for at least 90 days as well as 48 from manufacturer-delivered lots that had been approved for installation by Duke Energy Ohio's meter lab. In addition, 93 traditional electric meters were selected at random for comparative testing. The tests for gas meter data transmitters included tests of radio frequency used to communicate gas meter data to data concentrators. The electric meter tests did not consist of such testing as electric meters use power line carrier to communicate meter information to the data concentrators.

Unlike the gas meter data transmitters (see below), electric meters were not tested for RF emissions. The smart electric meters installed by Duke Energy Ohio communicate through the power lines themselves using a protocol known as Power Line Carrier or PLC. The Duke Energy Ohio smart meters do not communicate wirelessly and therefore generate no RF emissions.

Gas Meter Data Transmitter Tests

Gas meters were not replaced as part of Duke Energy Ohio's smart grid deployment. Instead, wireless data transmitters were retrofitted to existing gas meters to enable remote meter reading. Accordingly, gas meter accuracy was not tested as part of this audit. Gas data transmitter tests consisted of RF emissions testing as well as data transmission accuracy (covered in Section 2, "Systems Integration"). Forty-eight gas meter data transmitters were selected at random from an inventory of data transmitters about to be installed. The photograph below illustrates a typical gas data transmitter installation, with the device (box with black dials affixed with red screws) retrofitted onto an existing gas meter.

It is noteworthy that the data transmitters do not modify the function or accuracy of the gas meter but merely repeat and transmit gas meter data readings.

Gas meter data transmitters emit RF as part of normal operations. RF emissions from electronic equipment are regulated by The Code of Federal Regulations (CFR) 47, part 15. This Federal Communication Commission (FCC) regulation sets specific requirements so that various electronic devices do not interfere with each other's operation. In today's modern society exposure to radio frequency waves is a common occurrence. Light switches, cellular telephones, cordless home telephones, garage door openers, microwave ovens, wireless data modems, and FM radio station transmitters represent a few of many examples.

In fact, RF-emitting devices are so prevalent that testing RF emissions is difficult without special equipment to minimize extraneous RF signals. Alliance Calibration utilized a semi-Anechoic (RF) Chamber (a soundproof room similar to a music recording studio) to minimize ambient RF and enable accurate gas meter data transmitter testing.

Duke Energy provided gas meters to facilitate data transmitter testing. A known volume of gas was pumped through the gas meters and both the physical readings on the dials and the signal sent from the meter data transmitters was recorded. An Alicat gas calibration unit with an accuracy of ± 0.4 % was used to measure the known volume of gas; like the electric meter testing equipment, the calibration of the Alicat unit is traceable to NIST.

Wide band RF characterization measurements were taken from data transmitters at rest and while transmitting to determine the frequencies at which significant RF emissions occurred. The measurements were taken at a distance of 3.0 meters. A variety of transmitter positions were tested and both horizontal and vertical field components were measured. The output of the antenna was connected to the input of the receiver and emissions were measured in the range from 30MHz to 1GHz. The values up to 1GHz with a resolution bandwidth of 120 kHz are quasi-peak readings made at 3.0 meters. The raw measurements were corrected to allow for antenna factor and cable loss. For detailed gas transmitter test plans please see Appendix 1-B: Gas Meter Test Plan and Appendix 1-C: Gas Transmitter Chamber Test Plan.

Distribution Automation Equipment Audit

The objective of the Distribution Automation Equipment Audits was to determine deployment status relative to completion as defined by the Duke Energy smart grid implementation plan approved by PUCO. MetaVu designed an audit that involved physical inspection of 'smart' equipment installed throughout the distribution grid and verification of equipment readings in Duke Energy's Energy Management System (EMS) system found in the Supervisory Control and Data Acquisition (SCADA) system. Those same readings were also compared to corresponding data found in the data historian. The results of the audit (based on a random sample) were extrapolated to estimate the Substation and Feeder/Lateral deployment levels as a percent of the total project.

Duke Energy provided a list of installed smart equipment from its asset management system. MetaVu selected 25% of all substations that underwent smart grid upgrades in 2009 or 2010 as a random sample set "inside the fence." Of this sample set a Physical Field Audit was completed for all the smart grid-enhanced hardware, including Circuit Breaker Protective Relays (CB Relays), Voltage Regulators (VR) and Transformer Load Tap Changer Controllers and the respective communication transceivers.

A random sample set of smart switching equipment "outside the fence", laterally from the substations, was also selected and audited. This sample of lateral feeder equipment was all located on poles and/or overhead and consisted of electronic re-closing, self-healing, sectionalizing, and fault-isolating disconnectors, switches or circuit breakers.

An Alliance Calibration technician supported the physical inspection and documentation aspects of the field equipment audit. Accompanied by a MetaVu electrical engineer, the technician participated in Duke Energy substation and field safety training. MetaVu instructed the technician on audit requirements and protocols, which included:

- Documentation of the street address of selected assets
- Photographs of selected assets

- Documentation of manufacturers, models, serial numbers, and installation dates of selected assets
- Date and timestamp of the inspection
- For a subset of applicable equipment:
  - A time-stamped display reading or a switch position indication
  - A real-time call to the EMS operator to compare equipment display readings or switch position according to the EMS system
  - Duke provided information from the data repository for MetaVu to compare equipment display readings or switch position to readings in the field

The technician's day to day activities were guided by Alliance Calibration management with oversight from MetaVu. The technician, accompanied by Duke Energy personnel, completed the field inspection over several weeks in late March and early April.

2.3 Findings

Metering Audit

The metering audit concluded as follows:

- Smart electric meters are significantly more accurate in all weather conditions, offering significantly smaller measurement variability than traditional electric meters.
- Smart electric meter deployment lags planned deployment levels, ratably delaying anticipated economic benefits.
- Gas meter data transmitters accurately report gas meter measurements.
- Gas meter data transmitter RF emission levels are lower than the RF emission levels of other devices commonly used by consumers and meet FCC standards.
- Duke Energy meter lot testing and change-out procedures are adequate and consistently applied.

These findings are described in detail in the sections below.

Smart electric meters are significantly more accurate in all weather conditions, offering significantly smaller measurement variability than traditional electric meters.
Detailed tests of smart and traditional electric meters indicate that smart meters are much more accurate and offer reduced measurement variability than traditional meters. The table below summarizes the findings:

Average Meter Accuracy Results

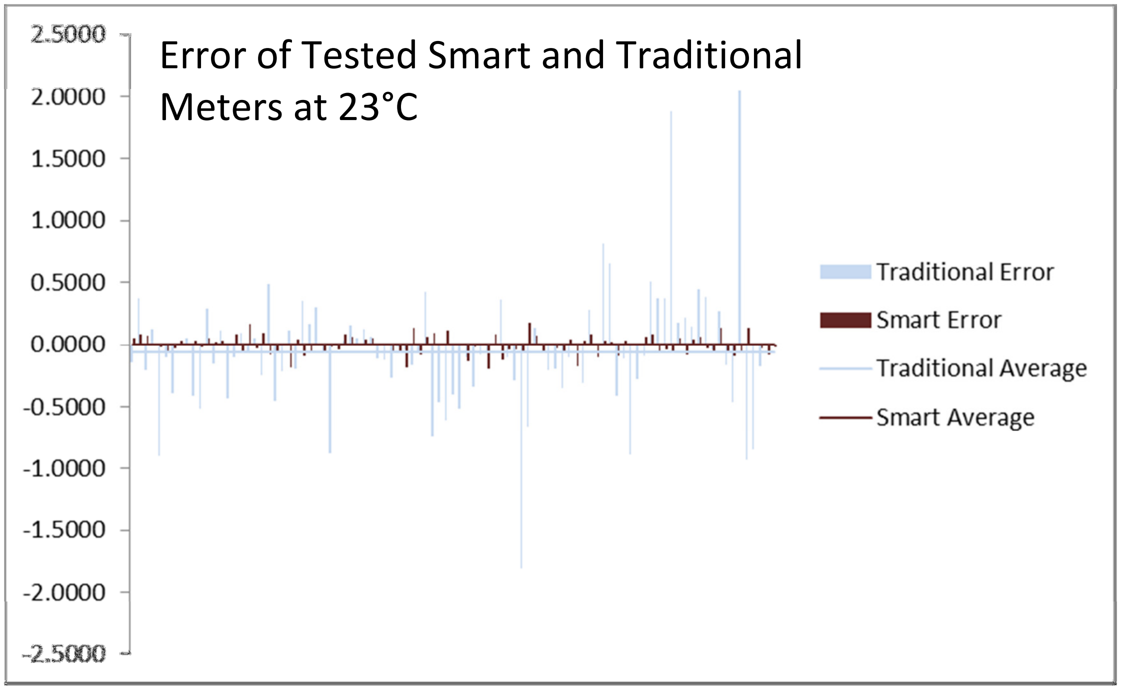
	Smart Meters, Passed Lots	Smart Meters in service 90 days+	Traditional Meters
+23°C Average % Error	0.004	-0.014	-0.061
+23°C Standard Deviation	0.073	0.079	0.494
+40°C Average % Error	0.442	0.455	-0.904
+40°C Standard Deviation	0.282	0.248	1.009
-40°C Average % Error	0.094	0.110	-0.178
-40°C Standard Deviation	0.105	0.122	0.541

"Error" is defined as the difference between actual load and the load indicated by the meters tested.

Graphical representations can help make the dramatic improvements in meter accuracy more apparent:

NOTES:

- Average Smart Meter Error: +.004%
- Average Traditional Meter Error: -.061%
- Smart meter sample size: 95
- Traditional meter sample size: 93
- Results of tests conducted at 23℃, average of 3 current loads tested
- ”Error” is defined as the difference between actual load and the load indicated by the meters tested.



While the tests show improvements in smart meter accuracy over traditional meters, it should be noted that the magnitude of these numbers is very small. Customers are not likely to notice a difference on their bills as a 0.004% error rate on a $50 bill is less than 20 cents. In the aggregate, however, the improvement in meter accuracy should increase billed sales volumes for Duke Energy Ohio. This is addressed in Section 4, ‘Operational Benefits’ under Benefit 8,”Meter Accuracy Improvement.”

Smart electric meter deployment lags planned deployment levels, ratably delaying anticipated economic benefits.
Several types of economic benefits associated with smart meters, from the aforementioned meter accuracy improvements to dramatic reductions in meter reading costs, are driven by the level of meter deployment. Due to a variety of factors, smart meter deployments have lagged planned deployments. These factors include:

- Difficulty accessing some meters, particularly those located within customer premises.
- Time required for the initial learning curve of meter installation.
- Difficulty in identifying a smart meter solution appropriate for some commercial/industrial customers.
- The need to upgrade premise meter facilities that have been made unsafe over time.
- Start-up delays associated with communications node design and production.

Operational Benefit estimates, utilizing meter deployment as a significant variable, have been adjusted accordingly.

Gas meter data transmitters accurately report gas meter measurements.
Data from 47 in-service gas meters was tracked in real-time from the meter to Duke Energy’s central gas meter data collection and management systems without error. Please see the Systems Integration Assessment section for more information.

Gas meter data transmitter RF emission levels are lower than the RF emission levels of other devices commonly used by consumers and meet FCC standards.
RF emission level testing of gas meter data transmitters revealed that RF emission levels are lower than FCC limits for such devices.

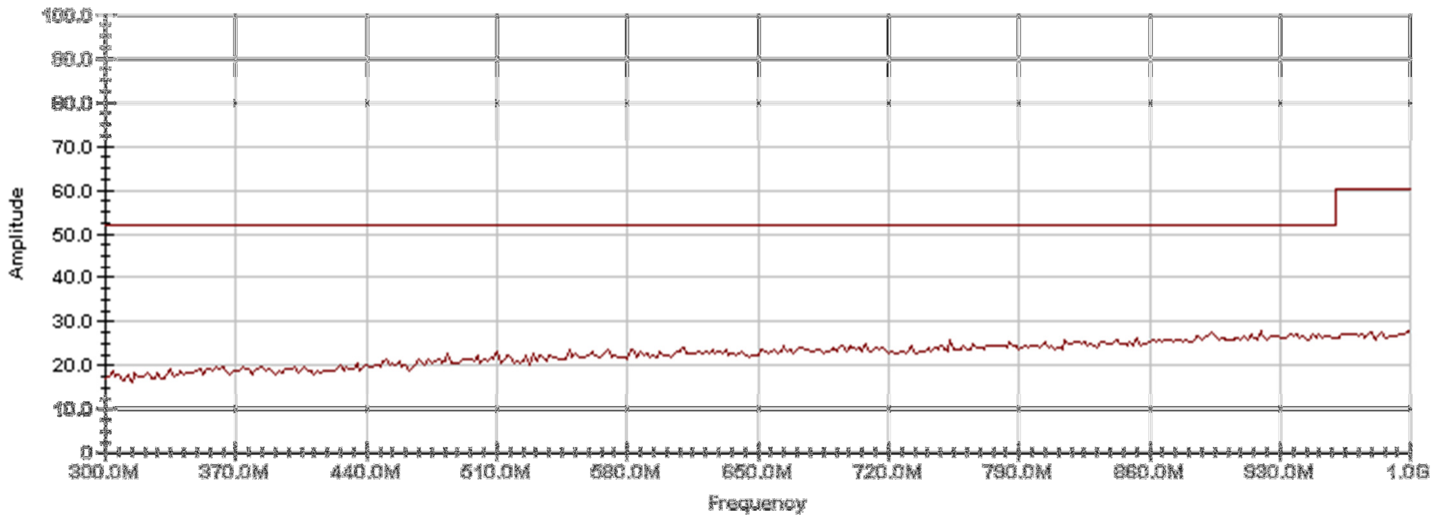
The chart below indicates the results of the test relative to the FCC limit (represented by the straight red line): RF signal strength was measured from a variety of locations to understand if the signal varied from different positions around the data transmitter, and no significant differences were found.

In some instances, such as apartment buildings, multiple data transmitters are installed tightly together. Alliance Calibration tested 12 co-located data transmitters to examine this scenario and found that RF signal strength was not additive. The gas meter data transmitter manufacturer has tested its equipment in a similar manner and submitted its findings to the FCC in compliance with CFR 47, part 15. Alliance Calibration examined the filing and found it to be consistent with findings of this audit.

F-Squared Laboratories

Spectrum Analyzer Trace Data

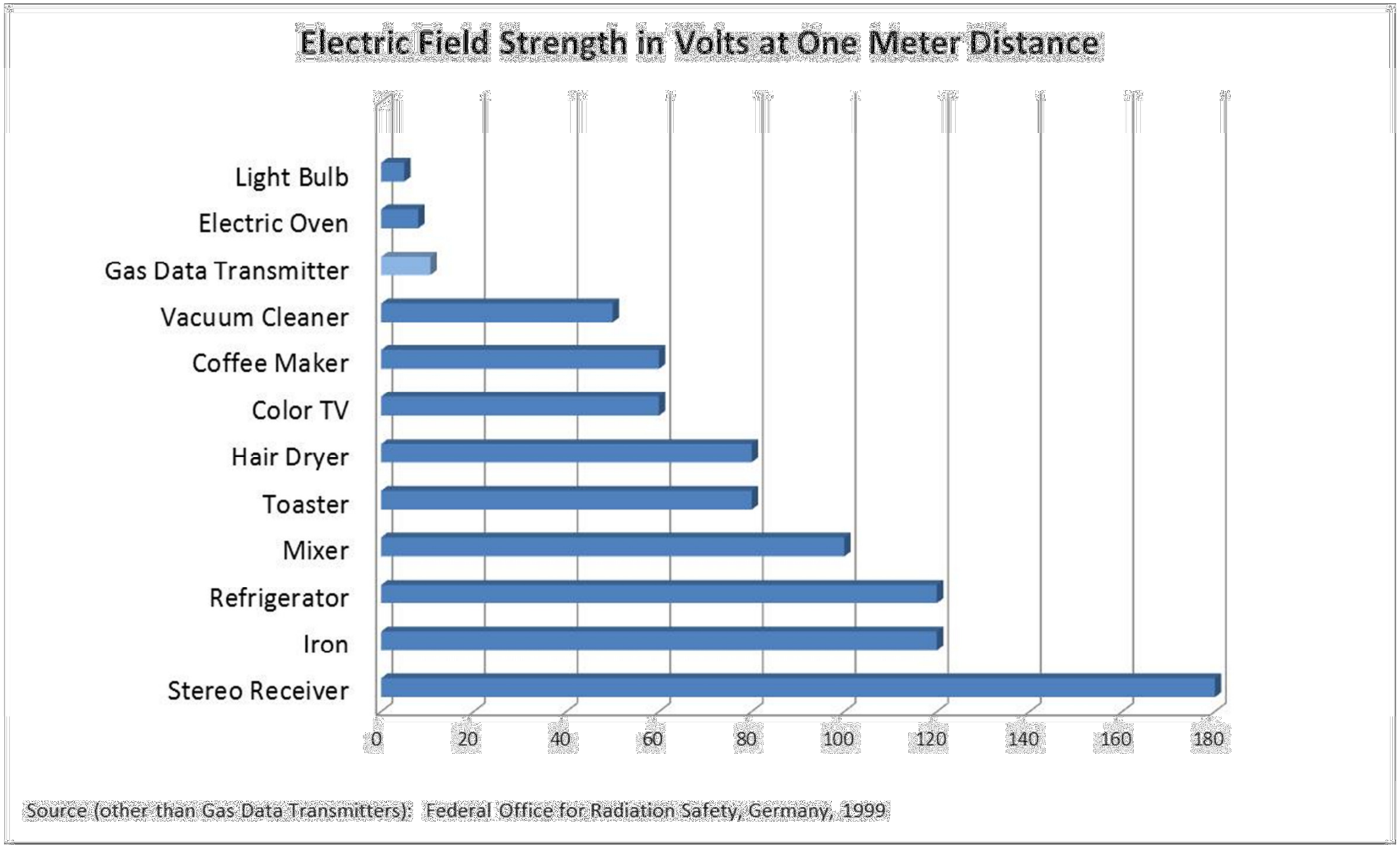
Corrected Graph

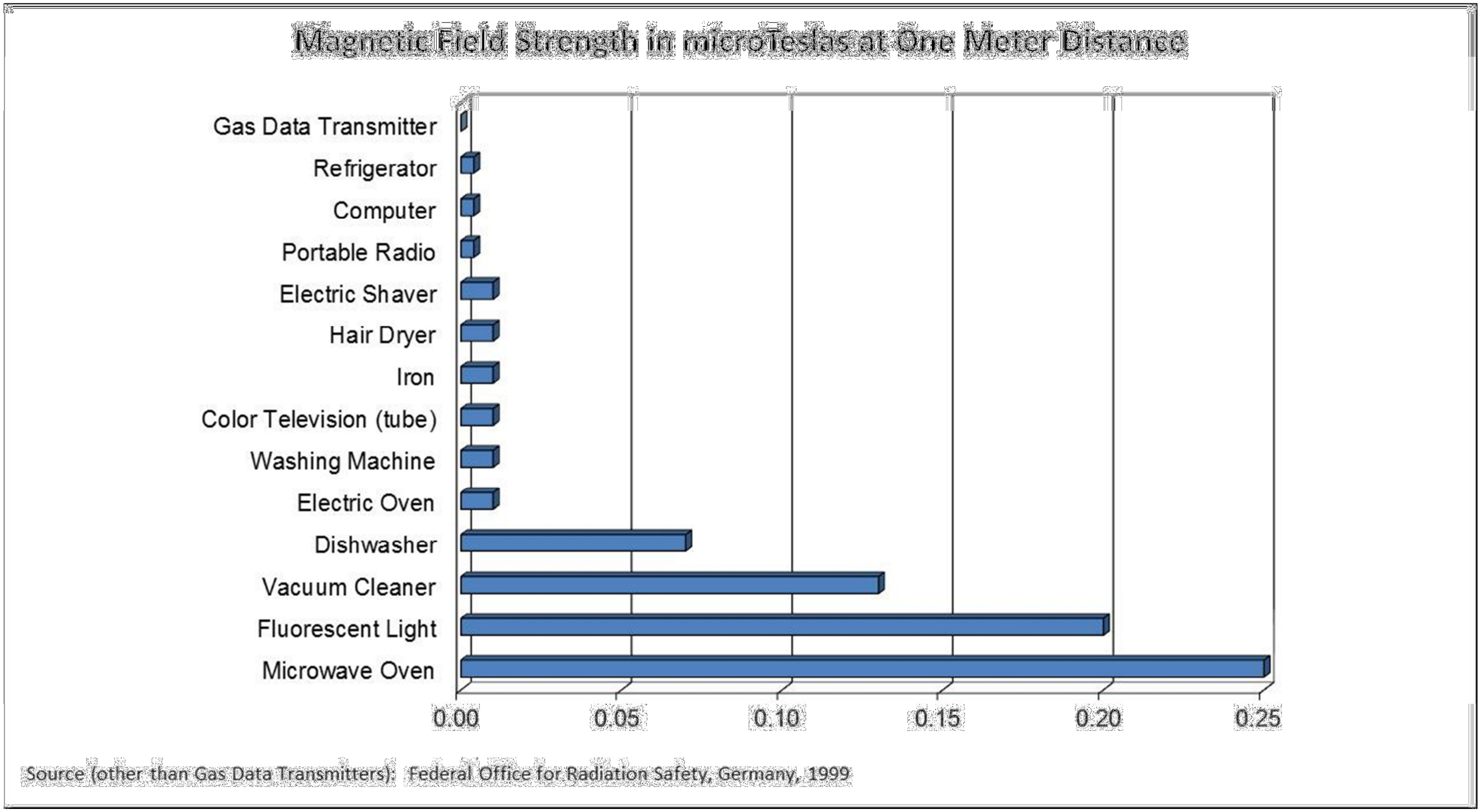


01:37:52 PM, Thursday, April 07, 2011

Company: Alliance Calibration

Duke Energy's Ohio customers may be interested to know that many of the devices consumers use on a daily basis emit significantly stronger Electro-Magnetic Frequencies (EMF) than the gas meter data transmitters. The following charts compare the gas meter data transmitters' findings by Alliance Calibration to the findings of a separate study of common household devices on electric and magnetic field strength at one meter distance.




Magnetic Field Strength in microTeslas at One Meter Distance
Gas Data Transmitter
Refrigerator
Computer
Portable Radio
Electric Shaver
Hair Dryer
Iron
Color Television (tube)
Washing Machine
Electric Oven
Dishwasher
Vacuum Cleaner
Fluorescent Light
Microwave Oven
0.00
0.05
0.10
0.15
0.20
0.25
Source (other than Gas Data Transmitters): Federal Office for Radiation Safety, Germany, 1999

Duke Energy meter lot testing and change-out procedures are adequate and consistently applied.
Alliance Calibration reviewed and observed processes employed at Duke Energy's electric and gas meter testing facility in Cincinnati as part of the Operational Audit. Alliance Calibration found the processes to be in compliance with electric and gas meter testing standards as described above. Duke Energy is currently testing 10% of the meters in a manufacturer's lot before approving the meters in the lot for installation. This is in excess of the amount required for minimum statistical significance. Alliance Calibration tested a random sample of meters from two lots approved by Duke Energy and found them suitable for installation.

Alliance Calibration also reviewed and observed the process by which traditional meters were removed and smart meters installed. Ninety-three instances of the process were observed as executed by eight different installers. These observations indicated that the new meters present no installation challenges. Meter mount modifications were not necessary and the swap-out process is described simply as "pull the old one out and plug the new one in."

All installers observed made consistent efforts to contact customers while on site and answer any customer's questions. All customers that were contacted by installers were advised to turn off any electrical devices such as computers. All installers observed waited for customers to turn off electrical devices before installing meters and consistently employed industry-standard safety procedures and installation methods.

Distribution Automation Audit

- The installation of "smart" equipment intended to reduce outage extent is on schedule with approximately 40% complete as of December 31, 2010.
- The installation of "smart" equipment in Duke Energy's Cincinnati substations is slightly behind plan with 31% complete as of December 31, 2010.
- The economic benefits of "smart" equipment intended to improve electric distribution efficiency is largely dependent on software with completion anticipated by 2013.
- The comparisons of device readings and data found in EMS and the data repository were found to be sufficiently accurate.

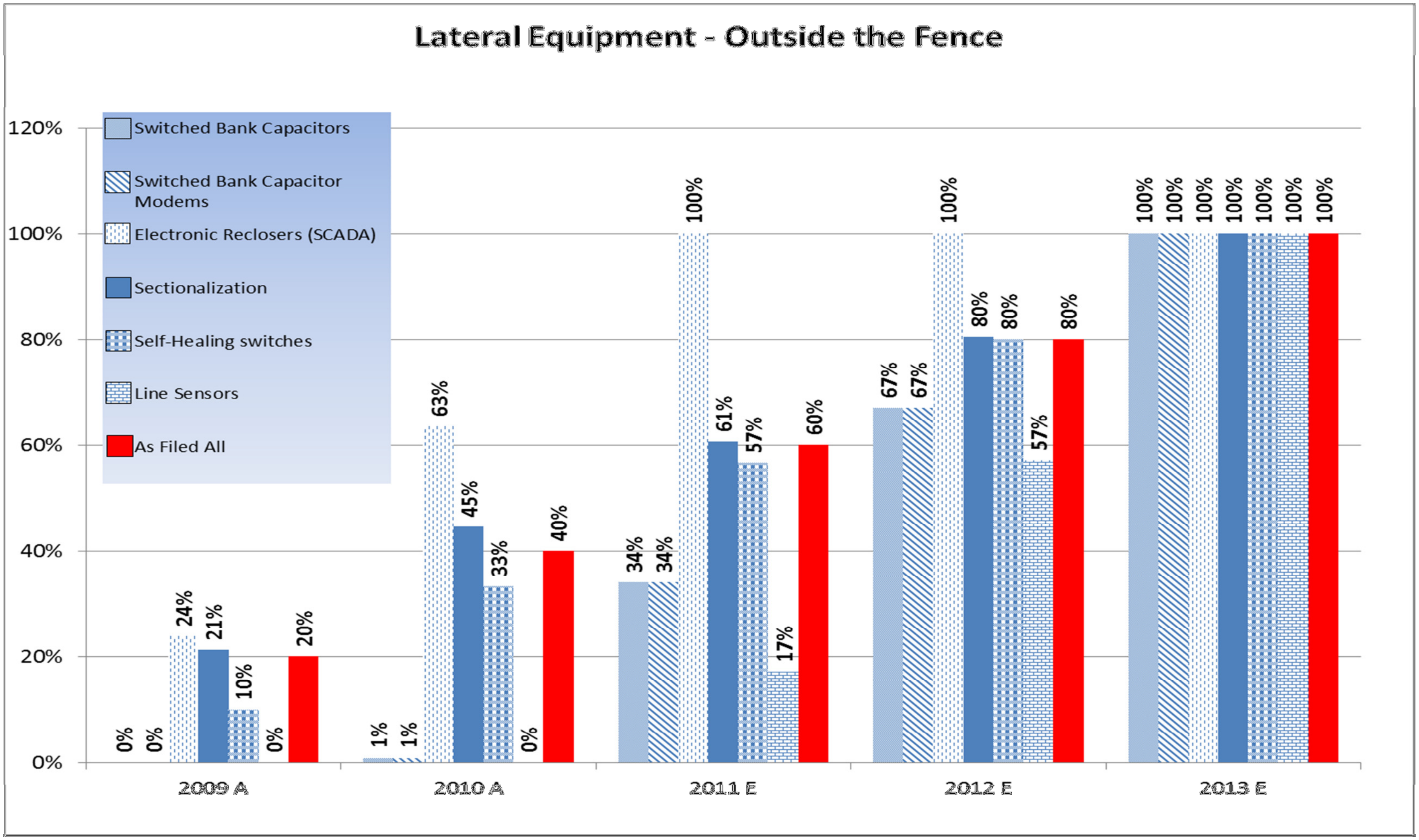
These findings are described in detail in the sections below.

The installation of "smart" equipment intended to reduce the length and extent of outages is on schedule with approximately 40% complete as of December 31, 2010.

Several types of smart equipment installed in the distribution grid are specifically designed to reduce the number of customers impacted by an outage or reduce the time required to locate the source of an outage (known as "Fault Isolation and Outage Detection"). The use of these devices, including reclosers, sectionalizers, and switches, has been commonplace for some time, but the number of devices installed and the extent to which they communicate data and operate automatically is significantly greater in smart grid applications.

"Smart" versions of these devices are more effective than traditional versions at reducing "Customer Minutes Out", a common measure of grid reliability. MetaVu's audit of these devices indicated that the installation of such devices is on schedule, and that approximately 40% are installed as of December 31, 2010.

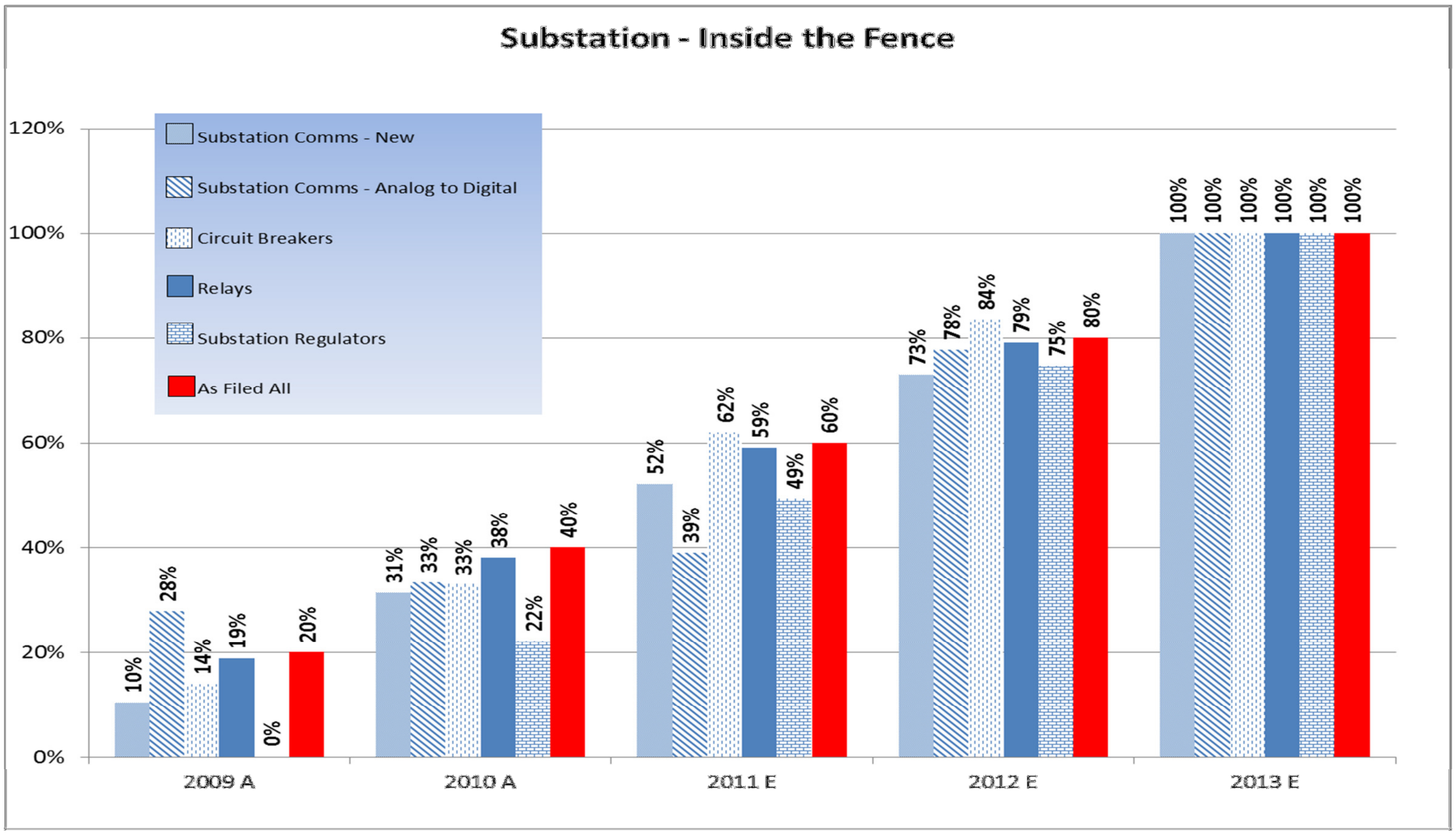
MetaVu's audit of smart substation equipment indicates that upgrades are on schedule, and that about 31% of the work and spending to finish the approved implementation plan relative to substations is complete as of December 31, 2010. The chart below describes MetaVu's audit findings for substation equipment installation rates, including historical actuals and future projections based on actuals:



The installation of "smart" equipment in Duke Energy's Cincinnati substations is slightly behind plan with 31% complete December 31, 2010.

Substations play a critical role in the smart grid and house a great deal of the smart equipment required to secure anticipated reliability and economic benefits including communications, circuit breakers, relays, and voltage regulators.

MetaVu's audit of smart substation equipment indicates that upgrades are on schedule and that about 31% of the work and spending to finish the approved implementation plan relative to substations is complete as of December 31, 2010. The chart below describes MetaVu's audit findings for substation equipment installation rates, including historical actuals and future projections based on actuals:



The economic benefits of "smart" equipment intended to improve electric distribution efficiency is largely dependent on software with completion anticipated by 2013.

The reader may have noted from the "Lateral Equipment – Outside the Fence" chart above that installation of some on the smart equipment has just begun. This equipment, including capacitor bank controllers/ communications as well as line sensors, are specific to Duke Energy's Distribution Management System, or DMS, which is currently being installed and is scheduled for full operation in 2013. The "de-prioritization" of the installation of this equipment is therefore appropriate, as associated benefits are not anticipated to be significant until the DMS is fully operational.

The fact that the DMS and associated hardware will not be fully operational until 2013, however, does have implications for economic benefits. The DMS application that will make greatest use of the capacitor bank controllers/communications and line sensors is IVVC. Currently, Duke Energy Ohio is conducting IVVC pilots and has yet to select the technology and algorithm to be integrated into DMS. IVVC offers significant economic benefits in terms of distribution efficiency as it helps reduce voltage and associated power generation within the lowest tolerances according to standards and improves the VAR (power factor). Improving the power factor increases the amount of usable power available to customers for every unit of power generated.

These improvements in distribution efficiency are among the larger economic benefits available from smart grid implementations. Operational Benefit estimates, associated with IVVC operation calculated elsewhere in this report, have been assumed to begin in 2013.

The comparison of device readings and data found in EMS and the Data Historian was found to be sufficiently accurate.

All the equipment selected for Audit was found to be installed. All display readings and switch position indicators matched up with EMS in real-time. All display readings also matched subsequent examination of the Data Historian but for one switch position exception. It is reasonable to conclude that the switch position not matching the Data Historian could be attributed to "noise" in the measurement because everything matched up in real-time. The cause of this is most likely a human error and can be attributed to one or more of the following:

- The time stamps captured were inaccurate
- The switch position was written down incorrectly
- The switch was operated within a minute of the physical audit (time stamp was rounded to nearest minute)
- Duke operator may accidently have given inaccurate switch position from the data historian

Therefore, MetaVu determined that data from DA field devices is being communicated to the EMS and Data Historian accurately.

3 SYSTEMS INTEGRATION ASSESSMENT

3.1 Introduction

Staff asked MetaVu to review Systems Integration in terms of "the degree to which Smart Grid components work together with other components and systems." MetaVu interpreted this definition somewhat broadly, incorporating both information technology systems and associated business processes into its assessment.

The Systems Integration Assessment findings are organized into areas of investigation specified by the Staff:

- Electric Data Audit
- Gas Data Audit
- Time-Differentiated Billing Data Audit
- Billing Data Validation, Estimation, and Editing
- Meter Outage Data integration for MAIFI Reporting
- Distribution Automation Integration
- Meter Data Integration

This Introduction concludes with diagrams that illustrate the data paths and information systems of Duke Energy Ohio's Advanced Metering Infrastructure (AMI) and smart distribution grid. The balance of the Systems Integration section includes descriptions of audit methodologies and is followed by audit findings organized into Advanced Metering Infrastructure and Distribution Automation components.

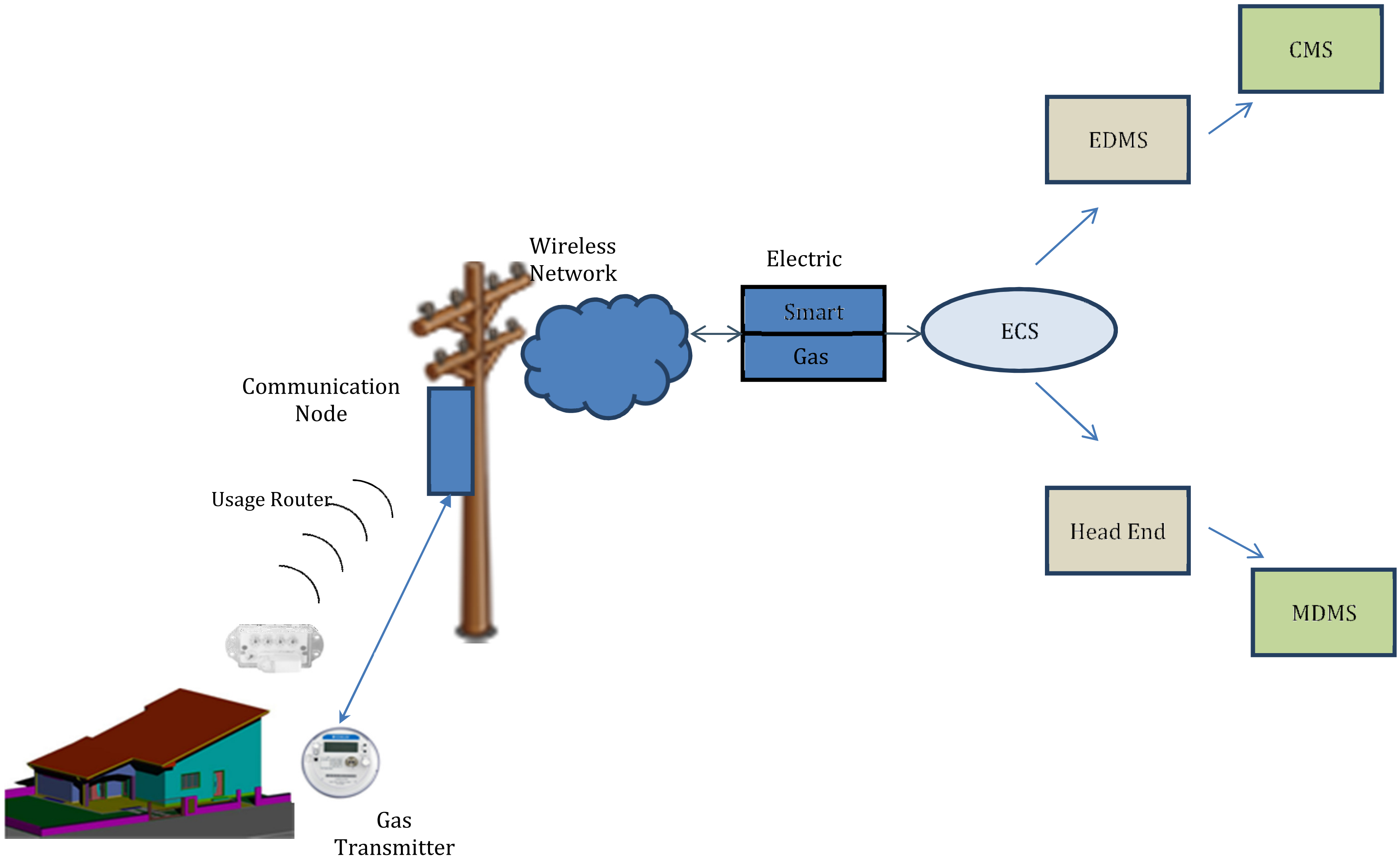
An appreciation of system architectures is helpful to understanding the System Integration findings presented in this Assessment. Though there are opportunities for integration, smart grid system architecture can be simplified by considering distinctly the two primary smart grid systems, Advanced Metering Infrastructure and Distribution Automation.

Advanced Metering Infrastructure

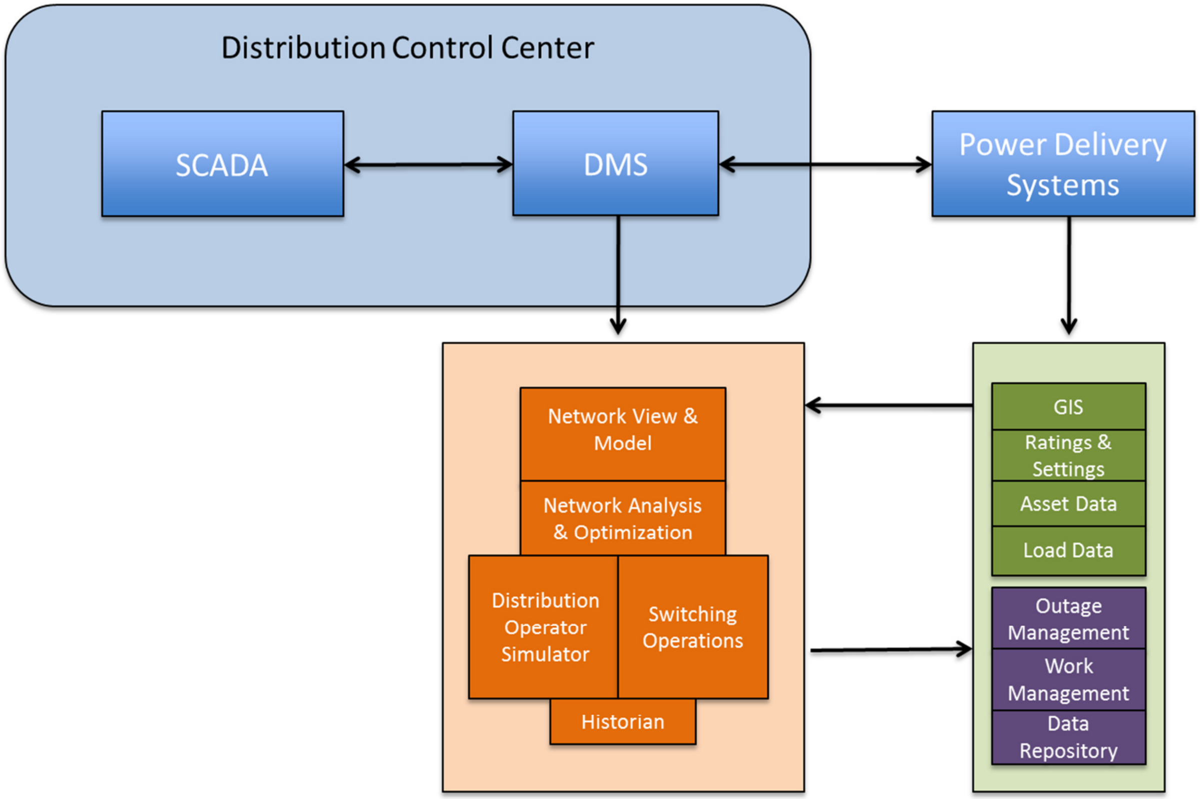
Duke Energy's Ohio AMI begins with customers' smart meters where usage data is recorded, and ends at the customers' bills where usage data is reported. A diagram of the manner in which meter data is collected, analyzed, and processed is shown below. Aspects of the metering system not associated with "smart" metering have been omitted for clarity.

Distribution Automation

Duke Energy's Distribution Automation (DA) system is the application of automated and sensing technology equipped with bi-directional communication throughout the distribution system, combined with application software, to improve energy efficiency and reliability. The Duke Energy Ohio DA system is currently being implemented.


CMS
EDMS
Wireless Network
Electric
Smart
Gas
ECS
Communication Node
Usage Router
Head End
MDMS
Gas Transmitter

The plan is to deploy smart grid devices to produce operating characteristic data, such as voltage, current, etc. throughout the distribution grid. The data will be analyzed and processed in real-time to assist in grid operation and will be stored for retrospective analysis. A diagram of the planned collection, analysis, processing, and storage of grid operating data is shown below.



3.2 Methodology

The evaluation of Systems Integration consisted of both data collection efforts from a series of System Integration specific data requests and general observations made while collecting data for other components of the Assessment project. The data collection efforts specifically focused on Systems Integration consisted of the following steps:

- Inventory distribution field hardware to be installed as part of the deployment
- Inventory information systems that utilize data generated by field hardware
- Document information systems’ roles in business processes, functions, usage, and data flows
- Review information systems’ implementation plans (for systems not yet fully functional)
- Examine detailed customer usage data (for meter data and time-differentiated billing audits).

These data collection efforts were pursued through documentation provided by Staff and through interviews with Duke Energy personnel, information provided by Duke Energy in response to specific data requests, and a structured investigation of information technology systems, including software demonstrations and desktop research.

Inventory Distribution Automation Field Hardware to be Installed as Part of the Deployment

Staff provided a list of field hardware to be installed as part of the deployment, which was subsequently updated by Duke Energy in response to a specific data request. The updated field hardware list served as the list used for physical verification of devices and for devices used to track data from the field into EMS and the data repository.

The list of data-generating field hardware included both metering and distribution grid devices:

Advanced Metering Infrastructure Devices

- Smart (electric) Meters
- Meter (Gas) Wireless Data Transmitters

Distribution Automation Devices

- Line Sensors
- Recloser Controllers
- Capacitor Bank Controllers
- Self-healing Switches
- Voltage Regulators and Load Tap Changer Controllers
- Circuit Breaker Relays
- Remote Telemetry Units (RTUs)
- Communications Equipment

Inventory Information Systems that Utilize Data Generated by Field Hardware

MetaVu utilized a structured interview process to create an inventory of information systems that utilize or are envisioned to utilize, data generated by smart field hardware. The list of information systems included both AMI and DA systems:

Advanced Metering Infrastructure

- Electric meter data head end (the system for collecting data from smart electric meters)
- Gas meter data head end (the system for collecting data from gas meter wireless data transmitters)
- Energy Data Management System (EDMS, used to store data for use by the Customer Management System)
- Meter Data Management System (MDMS, used to store data for use by the Enterprise Customer System)
- Customer Management System (CMS, the primary customer billing system)

- Enterprise Customer System (ECS, the billing system used to create time-differentiated bills for the Duke Energy Ohio residential pilot rates).

Distribution Automation

- SCADA (Used by Duke Energy's Distribution Control Center personnel to monitor and manage the grid today)
- EMS (similar to SCADA, but focused primarily on substations and transmission)
- DMS (the epicenter of the smart grid, automating many new distribution capabilities and providing new levels of visibility and control of the distribution grid beyond the capabilities of SCADA)
- Data Historian (used as a repository of operational data)

Document How Information Systems Are Used in Business Processes and Functions

MetaVu documented how information systems are used in business processes and functions as part of the Systems Integration assessment. This documentation was accomplished through 4 primary means:

- Interviews with managers and users of various systems
- Live "white boarding" sessions with managers and users
- System demonstrations
- System documentation reviews

Review information systems' implementation plans (for systems not yet functional)

Various information systems associated with Duke Energy's Ohio smart grid deployment are being implemented over several years. While the AMI systems are already integrated and being used to bill customers today, Duke Energy plans to integrate multiple new systems into its existing distribution grid architecture by 2013. The centerpiece of these integration efforts for the DA system is the DMS.

MetaVu reviewed Duke Energy's DMS implementation plans and previewed the DMS in a test environment in order to render opinions on related System Integration. The reader is cautioned that MetaVu's assessment of systems that have yet to be implemented (such as DMS) is based on implementation plans which may change over time.

Examine detailed customer usage data (for meter data and time-differentiated billing audits)

MetaVu submitted specific data requests to Duke Energy to collect the information needed to audit billing data. Examples of such data requests include:

- Historical data from smart electric meters removed from the field for testing and corresponding historical data from various information systems associated with the smart metering infrastructure
- Remote meter reads of gas meter values simultaneous to physical inspection as part of the gas meter wireless data transmitter testing
- Real-time queries of field data from distribution grid equipment
- Historical data from the MDMS and corresponding customer bills of those participating in Duke Energy Ohio residential rate pilots.

3.3 Findings

Electric Data Audit

Staff requested that MetaVu evaluate the quality of the smart grid deployment's data communications processes and customer bill accuracy. MetaVu did this by auditing the data from specific meters and comparing it with corresponding data in the EDMS and the CMS. By examining data on both sides of a communication node, the audit tests the quality and accuracy of the communications node itself.

As part of the meter accuracy test described in Section 1, "Operational Audit", Duke Energy removed 47 smart meters that had been in operation for over 90 days. These meters were selected at random from a list provided by Duke Energy. Meter removal was observed and meter testing conducted by Alliance Calibration. Historical data available from these meters' on-board memory was downloaded by Duke Energy and provided to MetaVu for analysis. The primary data sets evaluated included energy usage measured in 15-minute intervals ("interval" data) as well as energy usage measured on a daily basis (known as "scalar" reads).

Simultaneously, MetaVu requested 15-minute interval meter data from Duke Energy's electric head end and EDMS systems. In addition, daily scalar data was requested for the electric head end, EDMS and CMS systems. MetaVu then compared the data downloaded from the meters' on-board memory to the data stored in the electric head end, EDMS and CMS system for each of the meters. (Interval data was not tracked to CMS, as CMS is not utilized for customers choosing to be billed on time-differentiated rates.) The comparison indicated that 100% of 15-minute interval and scalar data from the evaluated smart meters was accurately reflected in both the electric data head end and EDMS systems, and that scalar data was accurately reflected throughout all the systems. This result indicates that all of the components between the smart electric meter and billing system are functioning effectively:

- PLC communications from smart meters to electric data collectors
- Electric data collectors within the communications nodes located throughout Duke Energy's Ohio service territory
- Cellular telecommunications infrastructure between the communications nodes and electric data head end system
- The interface between the electric data head end system and the EDMS meter data management system
- The interface between EDMS and the CMS

Gas Data Audit

MetaVu also evaluated the quality of the data communications processes and customer bill accuracy for the gas wireless gas data transmitters installed on existing gas meters. A different process was used to evaluate the gas transmitter data communications as the equipment and data collection process is different from those employed by the smart electric meters.

The comparison of physical meter reads to the on-demand meter reads available in the gas meter data head end system revealed that the physical readings taken from the 47 meters were 100% accurately reflected in the gas meter data head end system and the EDMS system. This indicates that all of the components between the gas meter and the gas data meter head end system are functioning effectively. This includes:

- Gas meter wireless data transmitters on customers' meters
- Gas data collectors within communications nodes
- Cellular telecommunications infrastructure between the communications nodes and the gas data head end system
- The interface between the gas data head end system and the EDMS meter data management system

Time-Differentiated Billing Data Audit

MetaVu was asked to verify the accuracy of customer bills calculated under time-differentiated rates. This was accomplished by retrieving interval data from the MDMS, the last stop for interval data prior to the creation of a time-differentiated customer bill. Twenty five customer bills on the Ohio Time-of-Use pilot program were selected for analysis. Interval data corresponding with those selected customer bills was extracted from the MDMS and used to calculate billed kWh amounts by hand according to published tariffs. Hand calculations were then compared to the kWh totals in customer bills to verify accuracy. The comparison of hand calculations from MDMS 15-minute interval data to customer bills was entirely accurate for every bill on both rates.

Of the 25 customer bills, 12 consisted of TD-AM rates and 13 of TD-LITE rates.

TD-AM rating periods as defined by Duke Energy:

- Summer On-Peak Period – 12:00 p.m. to 7:00 p.m. Monday through Friday, excluding holidays
- Summer Shoulder Period – 9:00 a.m. to 12:00 p.m. and 7:00 to 10:00 p.m. Monday through Friday, excluding holidays
- Winter On-Peak Periods – 7:00 a.m. to 1:00 p.m. and 5:00 p.m. to 10:00 p.m. Monday through Friday, excluding holidays
- Winter Shoulder Period – 6:00 a.m. to 7:00 a.m. and 1:00p.m. to 5:00 p.m. Monday and Friday, excluding holidays
- Off-Peak Period – All hours Monday through Friday not included above plus all day Saturday and Sunday as well as all says designated as national holidays

TD-AM Billing Periods

- Summer period is June 1 through September 30
- Winter period is October 1 through May 31

TD-LITE rating periods as defined by Duke Energy:

- Summer On-Peak Period – 2:00 p.m. to 7:00 p.m. Monday through Friday, excluding holidays
- Winter On-Peak Period – 7:00 a.m. to 1:00 p.m. Monday through Friday, excluding holidays
- Off-Peak Period – All hours Monday through Friday not included above plus all day Saturday and Sunday as well as all days designated as national holidays

TD-LITE Billing Periods

- Summer period is June 1 through September 30
- Winter Period is defined as December 1 through February 28 (29^{th} if Leap Year)
- All other days are defined as Spring/Fall

The 12 TD-AM bills included an On-Peak, Off-Peak and Shoulder rating periods. For each period, all kWh totals were accurate for all 12 customer bills.

The data for TD-LITE rates was extracted during the spring season. Therefore, no On-Peak period was used. As a result, only Off-Peak kWh was calculated and verified as accurate in all 13 customer bills.

Billing Data Validation, Estimation, and Editing

MetaVu was asked to review the adequacy of high/low meter reading validations utilized by Duke Energy in the bill preparation process. All utilities, including Duke Energy, utilize Validation, Estimation, and Editing (VEE) routines to identify customer bills that may be incorrect prior to issue. Customer bills identified as potentially incorrect are researched and edited if necessary; bills that cannot be readily researched and edited are estimated and issued. Estimated bills are reconciled at a later date as issues (missing meter read data, for example) are resolved.

Duke Energy uses a variety of data and communications checks throughout its smart meter data collection and processing procedures. These checks appear to be appropriate and effective at identifying, raising, and resolving data collection and communication issues. The checks through and including the electric and gas data head end systems are used to evaluate the presence and integrity of the data and do not evaluate the data for reasonableness. MetaVu concentrated its evaluation on the formal VEE routines utilized in Duke Energy's EDMS and MDMS meter data management systems that do perform reasonableness testing as part of the billing process.

The VEE routines in the EDMS system, which serves as the data source for bills calculated by CMS, focus on single, daily customer energy usage reads. These daily reads are called "scalar" reads which the CMS system uses for billing purposes. Thirty-two distinct VEE routines have been developed to evaluate data from various types of customers and meter configurations. Examples of the types of evaluations that are conducted within each of these VEE routines are "Compare energy usage to corresponding meter read yesterday" or "Compare energy usage to corresponding meter read last week". In the time period examined, 1.3% of meter reads violated established EDMS VEE parameters.

The VEE routines in the MDMS system, which serves as the data source for bills calculated by ECS, focus on both scalar reads and 15-minute interval data. Evaluation comparisons similar to those conducted in EDMS are also employed by MDMS VEE routines, but are configured for and applied to interval as well as a scalar data. These enhancements are important and appropriate, as accurate interval data is critical to the accuracy of bills calculated on time-differentiated rates. In the time period examined, 2.1% of meter reads violated established MDMS VEE parameters. The increase in violation ratio is a result of tighter VEE controls established for MDMS data and higher levels of data relative to EDMS. This is an intentional measure which Duke Energy intends to use to manage the new and more detailed time-differentiated rates billed from the MDMS system.

MetaVu's review of the EDMS and MDMS VEE routines indicates that meter data validations and associated business processes are adequate and appropriate for billing purposes. However, it should be noted that the larger volume of data evaluated by the MDMS VEE routines will invariably lead to larger volumes of VEE violations in MDMS, all else being equal. As MDMS is currently utilized to generate a relatively tiny portion of residential customer bills today, this has not yet presented a significant issue. However, as more customers participate in time-differentiated rates continuous refinement of MDMS VEE routines is advised so that the volume of bills violating parameters remains manageable. In effect, MDMS VEE routines must be held to a higher standard of accuracy than those in EDMS; failure to do so may result in higher staffing levels and/or an increase in the number of estimated bills. Duke Energy is aware of this situation and is monitoring it closely for potential process improvements as MDMS billing volumes increase.

Meter Outage Data Integration for MAIFI Calculations

Staff asked MetaVu to evaluate the capability of Duke Energy's AMI system to detect and transmit data in order to calculate MAIFI (Momentary Average Interruption Frequency Index), one of several measures of grid reliability. MetaVu conducted its assessment subsequent to a Commission docket on the issue. MetaVu's MAIFI assessment included both a review of information supplied by Duke Energy Ohio as part of the docket as well as MetaVu's own investigation of MAIFI measurement options within the Duke Energy Ohio smart grid.

MAIFI_E is the industry metric for average frequency of momentary service interruption events (defined as less than 1 to 5 minutes depending on the utility) and is to be calculated as follows per IEEE Standard 1366-2003:

$$\frac{Total\ Number\ of\ Customer\ Momentary\ Interruption\ Events\ (voltage = 0)}{Total\ Number\ of\ Customers\ Served}$$

Data that could be used to support the MAIFI calculations could conceivably come from two sources: the DA system or the AMI system. MetaVu's evaluation of the MAIFI issue indicates that neither approach offers a measurement that strictly complies with the IEEE calculation and that each offers pros and cons. A third option is not to measure MAIFI.

AMI-Oriented MAIFI Calculation

The smart meters Duke Energy Ohio selected for its deployment are able to count and store the number of momentary outages experienced by the meter. Duke Energy Ohio could conceivably retrieve this data on a periodic basis to calculate MAIFI. However, the meter manufacturer has verified that its meters define momentary outages as any instance in which voltage drops below 72% of nominal voltage (110 volts) for more than 12 cycles. If Duke Energy Ohio were to retrieve meter MAIFI counts, it would obtain MAIFI measures that reflected the meter manufacturer's definition and not the IEEE definition. Including the voltage drops in the MAIFI calculation introduces a number of drawbacks:

- Comparisons of Duke Energy Ohio MAIFI performance to that of utilities using the IEEE definition are difficult
- Customer activity can cause low voltage situations that would be counted in MAIFI inappropriately (as customer activity is a condition beyond Duke Energy Ohio's control)
- There are significant costs to collecting MAIFI meter data, to designing and developing software to organize and report the

MAIFI data, and for human resources to analyze and explain MAIFI report data.

Duke Energy estimated the costs associated with collecting and reporting quasi-MAIFI measures as part of the MAIFI docket. MetaVu reviewed the cost estimates and believes them to be reasonably accurate:

1. A one-time programming project - $241,515
2. Data gathering from the smart meter
    a. Daily basis - annually $524,954
    b. Weekly basis - annually $76,018
    c. Monthly basis - annually $18,646

In the event an AMI-oriented MAIFI calculation project is ordered by the Commission, MetaVu recommends that a formal project scoping and chartering exercise be completed to develop more formal project development and ongoing cost budgets. Additional ongoing costs would also be incurred such as analysis of MAIFI data, production of reports to communicate the data, and any follow-up efforts surrounding data questions or concerns.

Distribution System-Oriented MAIFI Calculation

Many of the devices to be placed on the distribution grid as part of Duke Energy Ohio's Distribution Automation effort present an alternative to AMI-Oriented MAIFI data collection, albeit with drawbacks. Many devices are intentionally designed to help avoid sustained outages, but may cause momentary interruptions in the process. Many of these devices, including reclosers, switches, and sectionalizers, will communicate operational data to a centralized data repository (the Data Historian) in Duke Energy Ohio's distribution automation design. This device operating data could be matched to the quantity of customers impacted by device operations as indicated by Duke Energy Ohio's Geographic Information System (GIS) and queried to collect the data needed for MAIFI calculations.

Unfortunately this approach to MAIFI data collection also suffers from drawbacks, including:

- Not all of the devices described above will be "smart", i.e., communicate operational data. Operating data associated with devices that don't communicate will not be available in the Data Historian and therefore would not accurately report MAIFI.
- There are significant costs to measuring MAIFI via this approach as well.

Discontinue MAIFI Reporting

The "do-nothing" alternative is also available. MetaVu does not render an opinion on this option, but did collect Duke Energy Ohio's perspectives on this issue:

- As customers prefer momentary outages to sustained outages, Duke Energy Ohio believes that System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are more appropriate measures of reliability than MAIFI.
- Duke Energy Ohio believes that improvements in SAIDI and SAIFI performance are often accompanied by deteriorating MAIFI performance. As evidence the Company cites that an outage that would have affected 2,500 customers for 2 hours in a traditional grid environment might impact 1,000 customers for 2 hours and 1,500 customers for only 1-5 minutes in a smart grid environment.

Distribution Automation Systems Integration

Duke Energy plans to implement a DMS to serve as the centerpiece of its distribution automation effort. DMS is critical to the achievement of distribution automation objectives. While smart grid field hardware generates large amounts of data, economic and reliability benefits stem from the manner in which the DMS translates the data into actionable information and automated execution. Note that some reliability benefits are available upon installation and do not require a DMS to deliver value. Duke Energy plans to interface many systems that currently operate independently to the DMS. A detailed 3-year deployment plan has been developed and execution is well underway. Resources and project management appear to be sufficient to execute the plan as scheduled. These observations indicate that the DMS deployment plans reviewed by

MetaVu are likely to be followed and that findings based on the deployment plans are relevant and valuable. This determination was made by MetaVu at the time of publishing this report and changes to future deployment plans may alter MetaVu's determination.

The deployment plans indicate that the following utility systems are to be integrated fully with the DMS:

- SCADA
- Distribution Outage Management System (DOMS)
- Workforce Management System (WMS)
- Data Historian

The plans also call for the DMS to make use of several types of data generated by systems that are not fully integrated, including:

- Geographic data
- Ratings and Settings data
- Capacity
- Asset data
- Load data

While many distribution automation economic benefits are based largely on a functioning DMS, much of the smart hardware being installed by Duke Energy today has immediate reliability benefits that are not DMS-dependent. Examples include automated sectionalizers and reclosers that isolate faults and reduce the number of customers affected by an outage.

As the DMS is being deployed, MetaVu suggests that a corresponding change management plan be developed and executed. The DMS (and the smart grid in general) offers new capabilities and multiple opportunities to create value for customers. Many organizational changes may be required to capture value for customers and some are already underway. Examples are numerous but include:

- Resource requirements may drop in some departments, such as meter reading, but increase in others, such as information technology.
- Distribution Control Centers may need to develop new processes for field crew dispatch as outage management and sectionalization become more automated.
- Field crews may need to develop new skills to be able to configure and troubleshoot the more sophisticated field hardware critical to DMS performance.
- Distribution capacity planning and reliability engineering have access to extremely large quantities of historical data which may help prioritize and optimize grid development.
- Reliability performance metrics and incentives may need to change as increases in some metrics (such as MAIFI) are necessary to enable improvements in other, more important metrics (such as SAIDI and SAIFI as described above).

A comprehensive change management plan oriented to smart grid capabilities can be extremely valuable in maximizing the value of smart grid investments and should address a variety of organizational and operational enhancement opportunities. These include:

- Changes to organizational strategy, structure, and resources suggested by smart grid efficiencies and opportunities (some of which are currently being evaluated by Duke Energy)
- Changes to operational processes, governance, policies, incentives, and performance metrics as dictated by smart grid capabilities
- Changes to information systems and tools to take advantage of new data types and characteristics
- Changes to organizational and human capabilities as existing capabilities are made redundant and new capabilities are required

Meter Data Integration

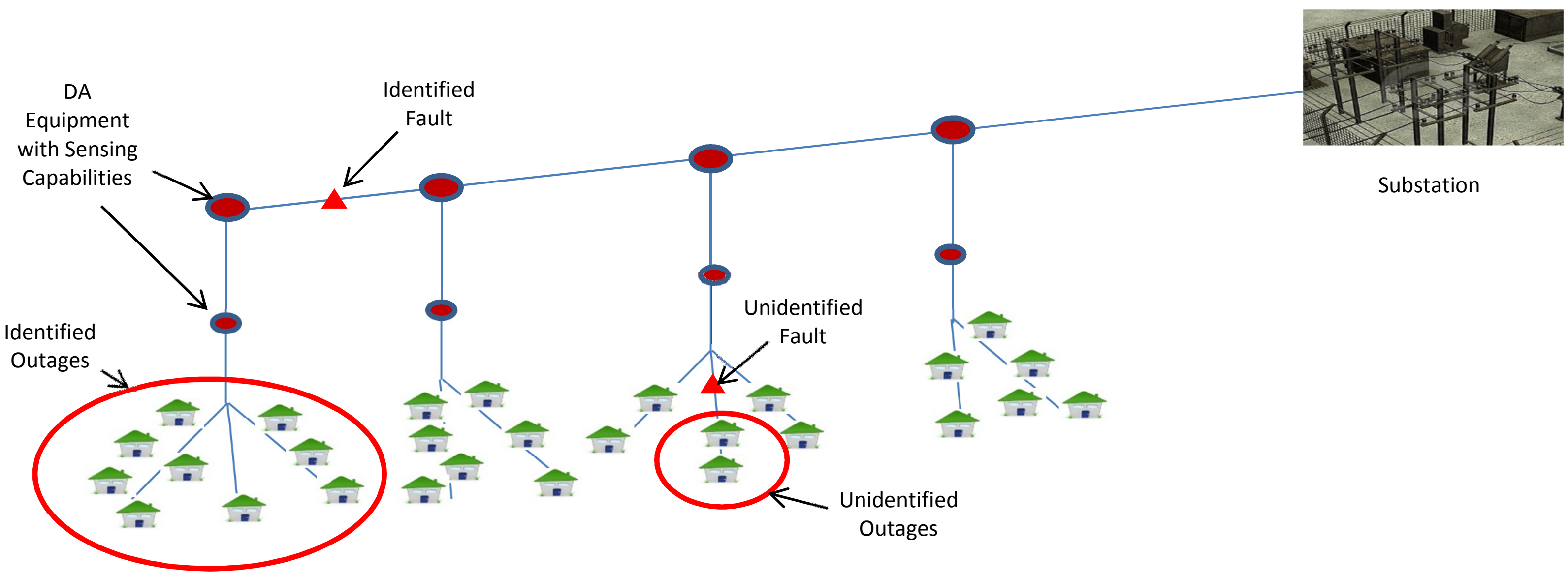
MetaVu found that the Duke Energy smart grid deployment is characterized by a distinction between smart metering systems, such as AMI and DA and the associated systems like DMS as described above. While MetaVu has found that this is typical among U.S. smart grid deployments it has examined, increased integration of meter data into the DMS and other systems nonetheless offers opportunities to increase the value of smart grid investments. Smart grid capabilities also present more general opportunities to improve the integration of business processes to maximize benefits. Although the size of the benefits and associated deployment costs vary widely between smart grid deployments, a few examples of potential meter data and business process integration include:

- Meter status for proactive outage detection
- Meter data for power quality (voltage)
- Meter data for capacity planning
- Meter data for load management verification
- Substation condition monitoring (such as oil temperature, pressure, and gas levels).

Meter status for proactive outage detection

One of the benefits commonly touted for the smart grid is that the utility, historically dependent on customer phone calls to identify outages, is now able to proactively identify outages without customer assistance. MetaVu's examination of the Duke Energy smart grid deployment indicates that the proactive outage notification capability will be available with the DMS deployment and the planned integration with DOMS with some limitations.

MetaVu's review of DMS deployment plans indicates that DA equipment will monitor and report data in real-time and that a combination of software and hardware will automatically take appropriate actions to minimize the number of customers impacted, alert repair crews, and alert the distribution control center. Outages must occur within the footprint monitored by smart devices for them to be identified. Outages that occur outside a DA-enabled area of the distribution grid will not be detected automatically.



(See the diagram above for an illustration of an outage outside the footprint of a smart device.) In these instances Duke Energy Ohio will still need to rely upon customers to report outages.

This issue is common to most smart grid deployments. Duke Energy is addressing the issue to some extent by deploying battery back-ups in selected communications nodes which enables exception reporting when the power goes out. There may be several ways to address this issue if deemed sufficiently important to customers, but all involve costs and tradeoffs. Additional cost/benefit analyses would be required to evaluate options and compare to customer-perceptions of value.

Meter data for power quality (voltage)

A similar situation exists for voltage reduction and management. The IVVC module in the DMS automatically adjusts the voltage of a feeder to ensure voltage is no higher than necessary yet still meets customer performance expectations. Reducing voltage in this manner avoids large amounts of electric generation and reduces customer fuel costs over the course of a year. Various smart grid designs employ different methods to determine a level that is no higher than necessary.

In traditional distribution grid designs, voltage is measured and controlled at the substation and in these designs customer complaints represent the feedback mechanism to let a utility know if voltage settings are too low. Utilities traditionally err on the side of caution, setting voltage higher than necessary to avoid complaints.

In the planned Duke Energy smart grid deployment, voltage is (generally) controlled at the substation but measured by the line sensors closer to customer premises at the “end of the line” (the location on a feeder where voltage issues are most prevalent). This can present a significant improvement as the DMS adjusts substation voltage continuously, in real-time, to a level with less safety margin. This reduces the amount of electric generation required for a given level of energy usage. A safety margin, though smaller, must still be employed as the voltage between the line sensors and customer premises must still be estimated.

In some smart grid deployments voltage measurements utilized by a DMS are taken at customer meters. This permits an even smaller safety margin, but comes with increased data collection costs. One solution may lie in identifying those customer premises located at the end of the line. Regular monitoring of voltage data from only these customers could serve as proxies for all the other customers on the line, reducing associated data collection costs. One limitation of this solution is that grid operating decisions based on a small customer subset (with potentially greater voltage variation) may be sub-optimal. Duke Energy is currently conducting several IVVC tests to better quantify the pros and cons of various approaches.

Meter Data for Capacity Planning

Historically, detailed meter data from individual customer premises can be aggregated by feeder, lateral, or transformer to dramatically improve the understanding of capacity needs. A better understanding of capacity “needs” can lead to improved transformer sizing and improved investment prioritization which can create beneficial delays in capital spending, improvements in reliability, and reductions in line losses.

In the course of MetaVu’s assessment there were many instances in which Duke Energy employees mentioned how meter data could be used in a Circuit Modeling Tool (CMT), a software tool which simulates various circuit load scenarios, to achieve these benefits. However, the effort to integrate meter data into the CMT appears to be in a very preliminary evaluation stage. MetaVu recommends that Duke Energy continue to pursue this potentially valuable integration effort.

A utility’s overall approach to data integration is important to maximizing smart grid value and merits some discussion. Some utilities are resolving the need for multiple applications to use the data generated by smart grid components through the use of a data “bus”. In traditional IT architectures, individual interfaces are built between an application and each of the other applications with which it must share data; this can result in higher maintenance costs and operational complexities. In bus architecture, applications send data to the bus, and other authorized applications pull data from the bus. Bus systems can reduce the effort required to integrate systems due to the relative ease of configuration and reductions in ongoing maintenance relative to traditional IT architectures. Of course, these benefits must be weighed against the considerable cost of implementing bus architecture.

Duke Energy IT policies state a clear preference for bus architectures, and MetaVu did find an example of bus architecture being used to integrate electric and gas meter data head end systems with the EDMS and MDMS meter data management systems. MetaVu believes the benefits of increased use of bus architectures within smart grid environments are potentially significant and likely worthwhile when viewed with a long-term perspective.

Meter Data for Customer Product and Program Optimization

Duke Energy's Power Manager® program helps the Company better manage peak loads by cycling participating customer's air conditioning compressors during peak demand periods through the use of wirelessly controlled switches. One drawback of such programs is that communication with the switches is unidirectional; that is, utilities can signal control intentions to the switches but there is no feedback to ensure the controls were implemented. A number of factors, from AC replacement to radio communications interference, can explain the difference between expected and actual load reductions from such programs.

Interval data collected from smart meters can be used to help confirm the accurate operation of Power Manager switches. This is only one of a number of examples in which smart grid capabilities can be employed to enhance energy efficiency and load management programs and portfolios. Another example is Duke Energy's use of customer interval data to establish usage baselines for Peak Time Rebate rate incentive calculations.

Substation Monitoring, Exception Reporting, and Forensic Analysis

Substation failures are rare, but result in widespread and sometimes extended outages as well as significant expenditures for repair. The upgrade of communication and data processing capabilities at the substation is a significant component of smart grid deployments and provides new opportunities for substation condition monitoring, exception reporting, and forensic analysis.

Although it is outside the scope of Duke Energy's initial smart grid business case, the monitoring of substation transformer oil characteristics, voltages, and other metrics in real-time offers a wealth of information to substation operators. MetaVu has observed that the incremental cost of monitoring devices is fairly minimal once enabling communications and data processing capabilities are installed in substations as part of smart grid designs. Forensic analysis can also be applied to historical monitoring data in the event of substation failure to facilitate root cause analysis in support of ongoing reliability improvement efforts. Software that analyzes the data and makes it actionable is necessary for these applications and increased employee costs may also apply.

4 GUIDELINES AND PRACTICES CONFORMITY ASSESSMENT

4.1 Introduction

Staff asked MetaVu to assess the degree to which the Duke Energy Smart Grid has been deployed in a manner consistent with the NIST Smart Grid guidelines and industry best practices as well as to identify the potential areas of improvement for complying with the guidelines and best practices.

The Assessment was conducted by MetaVu project partner OKIOK, an information technology (IT) and infrastructure security consultancy firm with specific expertise in secure data transfer, encryption and IT security compliance. The Assessment focused on the degree to which “Guidelines for Smart Grid Cyber Security” (NISTIR 7628) are addressed by the Duke Energy Ohio Smart Grid architectural design, implementation, and functions as well as Duke Energy corporate policies, standards, and procedures.

In addition to the conformity with the NISTIR 7628 that identifies high-level security requirements, privacy recommendations, and common vulnerabilities, OKIOK assessed whether Duke Energy adopted the guidelines identified and selected by the NIST Smart Grid Interoperability Panel (SGIP) and whether Duke Energy acknowledged industry security best practices. Thus the guidelines and practices included in the Assessment consisted of:

- NISTIR 7628 Volume 1 – High-level Security Requirements
- NISTIR 7628 Volume 2 – Privacy
- NISTIR 7628 Volume 3 – Common Vulnerabilities
- SGIP Interoperability
- Security Best Practices

About the NISTIR 7628

The security, privacy, and vulnerability issues covered by the NISTIR 7628 are a work in progress, scheduled to be updated every 18 months. They were chosen by the Cyber Security Working Group (CSWG) from existing standards documents such as NIST Special Publication 800-53 Recommended Security Controls for Federal Information Systems, DHS Catalog of Control Systems Security: Recommendations for Standards Developers, and NERC CIPs (1-9).

The NISTIR uses the word “requirement” to refer to security measures that are generally considered best practices or required to protect against well-known attack scenarios. *The use of the word “requirement” does not in any way imply that a specific measure is required in order to meet a given standard*. This document retains the “requirement” nomenclature utilized by the NISTIR 7628 for consistency.

How the NISTIR 7628 Was Used in the Assessment

Following the assessment of conformity with the NISTIR 7628, the families of controls and the practices associated with high risk were analyzed in more detail. Along with a brief description of the weaknesses identified, OKIOK provided hypothetical security break scenarios as well as high-level recommendations for Duke Energy to consider in order to mitigate the risk.

The NISTIR 7628 recommends that the organization perform a risk assessment on each individual smart grid information system in order to evaluate the impact level of a security breach and to decide which security requirements are to be selected. A risk assessment of this nature can only be performed by the organization itself and was not in the scope of this Assessment.

The Guidelines and Practices Conformity Assessment is valuable as it not only provides a mapping of the NISTIR 7628 security requirements with Duke Energy smart grid security controls but also evaluates the level at which the identified controls satisfy these requirements. The results provided by this assessment illustrate the conformity, alignment or congruity of the Duke Energy Smart Grid with the NISTIR 7628 and present to the reader a snapshot of the security controls in place in the Duke Energy Smart Grid.

Although the Assessment identified which existing controls from the Duke Energy smart grid conform with the NISTIR 7628 and to what level, it does not include evaluation of the effectiveness of the Duke Energy controls. Particularly, technical verifications on production systems such as penetration testing, having the purpose of identifying potential weaknesses of the Duke Energy security controls, were not within the scope of this Assessment.

Section Organization

A description of the Methodologies used to complete the Assessment follows this Introduction. Findings are organized into areas of investigation specified by Staff:

- The NIST Standards Development Process
- Conformity with Evolving Standards or Guidelines
- Risks of Nonconformity
- Practices Posing Redeployment Risks

4.2 Methodology

This section describes the methodology that was followed throughout the Guidelines and Practices assessment.

Review of the NIST Guidelines Development Process

Prior to assessing the conformity with evolving standards, the process used by the NIST Smart Grid Interoperability Panel to develop smart grid related guidelines and frameworks was reviewed.

In particular, OKIOK's review covered the two principal deliverables of the SGIP Cyber Security Working Group "Guidelines for Smart Grid Cyber Security" or NISTIR 7628 and "Standards for Consideration by Regulators". All five "families" of standards selected from those established by the International Electrotechnical Commission (IEC), were analyzed in order to observe current and potential future enforcement of recommended practices.

Assess Conformity with Evolving Standards and Guidelines

Following the identification of standards, guidelines, and best practices to be used as a reference for the assessment, recommended practices were analyzed resulting in a checklist of conformity items that covered all security requirements and recommendations within the scope of the assessment.

In order to correctly assess the conformity of the Duke Energy smart grid, data requests were placed with the purpose of receiving the documentation necessary for the Assessment. In the case where the responses to the data requests were not clear or incomplete, more specific data requests were placed. Overall, more than 600 documents were provided by Duke Energy and analyzed during the Guidelines and Practices Assessment.

Upon receipt of the responses to the data request, the documentation provided by Duke Energy was analyzed and the conformity of an item on the checklist was evaluated to one of the following values:

- *Fully conforms* – the documentation provided shows evidence and provides reasonable assurance that the security requirements or recommendations assessed are satisfied by security controls in place
- *Partially conforms* – the documentation provided shows evidence that some aspects of the security requirements or recommendations assessed are satisfied by security controls in place
- *Does not conform* – evidence providing reasonable assurance that the requirements and recommendations are addressed by existing security controls was not observed

Conformity items for which OKIOK did not observe either positive or negative evidence of satisfaction of the security requirements or recommendations by controls, were evaluated as “Does not conform”.

Preliminary results were provided to Duke Energy in the form of working papers in order to provide feedback and stimulate discussions. These discussions typically resulted in additional supporting documentation being provided by Duke Energy which was considered and evaluated during the assessment.

- Ideally, a security assessment would evaluate the satisfaction of all the security requirements and recommendations on each logical interface between the various smart grid information systems. Such an approach was infeasible within a reasonable timeframe and effort, due to the large number of smart grid logical interfaces and requirements and recommendations assessed and, was beyond the scope of work specified by Staff. A more practical methodology used to assess the conformity with items originating from the various sources is described below.

NISTIR 7628 Volume 1 – High level requirements

The NISTIR 7628 Volume 1 provides three types of security requirements:

- Governance, risk and compliance (GRC) requirements
- Common technical requirements
- Unique technical requirements

GRC requirements were evaluated against existing governance objects, i.e. internal policies, standards or guidelines applying either specifically to the Duke Energy smart grid or to the entire organization. For these types of requirements, evidence was sought that 1) governance objects addressing the GRC requirements exist and 2) that they are applied in practice. Documentation was accepted in various formats, such as internal policies, standards, procedures, reports, presentations, meeting notes, and emails.

Common technical requirements were evaluated against security controls in place for all smart grid information systems. For these types of requirements, evidence was sought that procedures, guidelines or tools to implement security controls were available and in use for smart grid information systems.

Finally, unique technical requirements were evaluated against security controls in place for specific smart grid information systems within the logical interface category to which the requirements are assigned. Similar to the common technical requirements, evidence of the controls being in place for systems assigned to the corresponding interface type, was sought.

Throughout the NISTIR 7628 Volume 1, requirements are allocated to impact levels, i.e. low, medium or high. The organization is expected to perform a risk assessment in order to evaluate the impact associated with a cyber security breach affecting the smart grid information systems and to select those requirements that apply to the evaluated impact level for each component of the smart grid information system. Performing an impact assessment on all of the Duke Energy smart grid information systems was not within the scope of this project. In addition, the requirements that were not allocated to any impact level were not evaluated during this assessment as they are provided as guidance for organizations that seek security requirements necessary to address specific risks and needs.

The objective of the NISTIR 7628 Volume 1 assessment was to provide a quantitative statement of conformity with proposed requirements. Because some proposed requirements are composed of several conformity items these items were assessed individually, as described previously, and evaluated to the following numerical scores:

- Items in Full Conformity were assigned a score of 100%
- Items in Partial Conformity were assigned a score of 50%
- Items in Not in Conformity were assigned a score of 0%

Following the evaluation of individual items, scores were aggregated and averaged to classify requirement conformity into one of the following categories:

- Requirements with an average score between 75% and 100% were assessed as Fully Conforming
- Requirements with an average score between 25% and 74% were assessed as Partially Conforming
- Requirements with an average score between 0% and 24% were assessed as Not Conforming

NISTIR 7628 Volume 2 – Privacy

The NISTIR 7628 Volume 2 – Privacy identifies potential privacy issues and provides recommendations based on the consumer-to-utility Privacy Impact Assessment (PIA) performed by the NIST SGIP privacy subgroup.

Similar to the GRC security requirements, privacy recommendations were evaluated against existing governance objects, i.e. written internal policies, standards or guidelines, applying either specifically to the Duke Energy smart grid or to the entire organization. For these types of requirements, evidence was sought that 1) governance objects addressing the GRC requirements exist and 2) that they are applied in practice. Documentation was accepted in various formats, such as internal policies, standards, procedures, reports, presentations, meeting notes, and emails.

The objective of the NISTIR 7628 Volume 2 assessment was to provide a quantitative statement of conformity with privacy recommendations.

NISTIR 7628 Volume 3 – Common vulnerabilities

The NISTIR 7628 Volume 3 presents analyses and references supporting the high-level security requirements described in Volume 1. In particular, chapter 6 presents a list of identified vulnerabilities that could adversely impact the operation of the electric grid. Therefore, the vulnerabilities presented in this section are matched to the security requirements described in Volume 1. The purpose of this list of potential vulnerabilities is to feed the risk analysis process for the smart grid information systems.

The objective of the NISTIR 7628 Volume 3 assessment was to identify whether the common technical vulnerabilities described are "acknowledged" by Duke Energy. For example, if a particular type of vulnerability was identified or tested by Duke Energy or by a third-party performing testing on behalf of Duke Energy on smart grid information systems, that certain type of vulnerability is considered to be acknowledged by Duke Energy for the purpose of this assessment.

It is important to note that if a vulnerability is assessed as being acknowledged by Duke Energy, it does not necessarily mean that all occurrences of that vulnerability have been detected or even that the identified occurrences of the vulnerability have been fixed. It simply signifies that Duke Energy is aware that the type of vulnerability in question can occur within the smart grid.

The approach used for the assessment of the NISTIR 7628 Volume 3 was also selected for the assessment of conformity with the recommendations from technical best practices, including NIST Physical Security Guidelines and Open Web Application Security Project (OWASP) Top 10 Web Application Security Risks.

Interoperability Standards

The Duke Energy Ohio smart grid deployment was assessed to evaluate the current and planned usage of interoperability standards selected by NIST. These standards generally describe communication protocols and data representation formats and are used to achieve logical interoperability. The approach selected was to identify and report on any reference to interoperability in the form of architecture and planning guidelines, specification and development requirements, or Request for Information / Proposal (RFI / RFP) criteria.

Risks of Nonconformity

One of the objectives of the Guidelines and Practices Conformity Assessment was to identify potential risks of nonconformity with emerging national guidelines and best practices. OKIOK performed an analysis of the NISTIR 7628 guidelines in order to identify the impact that each security requirement has on the potentiality of a security breach to occur. The security requirements described in the NISTIR 7628 Volume 1 were grouped into three categories:

- High Potentiality
- Medium Potentiality
- Low Potentiality

The logic supporting the grouping of requirements in categories of potentiality of a security breach to occur is presented above. It is important to note that this grouping was performed by OKIOK based on its experience in the field of information security and on actual or theoretical security breaches observed throughout the various projects it performed over the years.

High Potentiality

Requirements that have a direct and immediate impact on the probability of a security breach to occur, such as access control and prevention against malicious code, were grouped in the High Potentiality category. For example, access controls that prevent unauthorized access to critical systems are placed in this category.

Medium Potentiality

Requirements that have a medium-term impact on the probability of a security breach to occur, such as mechanisms that allow for the detection of security breach attempts by using monitoring and logging or requirements that address the response and restoration is case of a breach, were grouped in the Medium Potentiality category.

These requirements are considered to be at a lower level than the High Potentiality requirements because the absence of a detection mechanism by itself does not allow an attacker to modify the behavior of a system. However, an attacker might attempt to breach a certain system for a period of time without success until a particular context arises that allows the attacker to successfully attack the system. In this example, having a detection mechanism in place would allow the organization to detect that breach attempts are occurring and react accordingly.

Low Potentiality

Finally, requirements that have a long-term impact on the probability of a security breach to occur, such as policies, procedures, and standards ensuring that the security mechanisms are effective, updated, tested, and implemented throughout the organization when required, are grouped in the Low Potentiality category. Once again, these requirements are considered of a lower level than the High and Medium Potentiality requirements in the sense that the absence of security policies does not represent an immediate risk if the appropriate security controls are in place.

However, as the smart grid environment evolves, existing security controls might be deactivated in order to satisfy compatibility and operational needs, new systems might not have the security controls in place, and evolving systems might not have their security controls updated to address the changes that occur. In this context, the presence and enforcement of governance objects in the form of policies, procedures, and standards ensures the homogeneity and adequacy of security controls in place.

For the purpose of identifying risks of nonconformity with emerging guidelines, OKIOK analyzed the conformity of the current Duke Energy Ohio smart grid implementation with the NISTIR 7628 security requirements versus the potentiality of a security breach of each of these requirements.

The families of requirements that were found to have 25% or more of requirements associated with a high potentiality of a security breach **and** found to be in non-conformity were considered *High Risk*.

These families were analyzed in more detail by describing the weaknesses identified and presenting risk scenarios that illustrate the potential consequences of a security breach.

Finally, for each high risk family analyzed, OKIOK offers high-level recommendations for Duke Energy to consider in order to mitigate identified risks.

Identify Practices Posing Risks of Redeployment

Based on documentation analyzed during the security conformity assessment and on industry best practices, OKIOK identified practices that pose a risk that, if deemed unacceptable, may result in having to fix or redeploy components and systems.

Similar to the presentation of non-conformity risks, practices posing significant risks are analyzed in more detail by describing the weaknesses identified and presenting risk scenarios to illustrate the potential consequences of a security breach.

Finally, OKIOK considered countermeasures that could be put in place to mitigate identified risks. OKIOK recommends that Duke Energy perform a detailed and quantitative risk assessment for each of these risk scenarios to evaluate the potential cost associated with the security breach as well as the cost of implementing countermeasures. Based on OKIOK's analysis, Duke Energy might choose to accept the risk, implement the proposed countermeasures, or implement alternative countermeasures.

4.3 Findings

Findings are organized into areas of investigation specified by Staff.

- The NIST Standards Development Process
- Conformity with Evolving Guidelines
- Risks of Nonconformity
- Practices Posing Redeployment Risks

The NIST Standards Development Process

As outlined in the Energy Independence and Security Act of 2007 (EISA), NIST has been given "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems."[2]

NIST initiated the SGIP to fulfill its responsibility to coordinate standards development for the Smart Grid. Established in 2009, the SGIP is a public/private partnership comprised of over 600 member organizations representing 22 stakeholder categories, including federal agencies as well as state and local regulators.

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[2] Public Law 110 - 140, *Energy Independence and Security Act of 2007*, available at http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/content-detail.html.

Figure 4.3.1 illustrates the SGIP structure, as presented on the SGIP Wiki Collaborative Site.[3]

In 2009, NIST created the Cyber Security Coordination Task Group which was renamed the Cyber Security Working Group or CSWG, as part of the SGIP. The two major work efforts that have been completed by the CSWG are discussed in this section

- "Guidelines for Smart Grid Cyber Security" (NISTIR 7628)
- Standards Review

As discussed previously, the EISA assigns NIST with the responsibility of developing a framework for smart grid protocols and standards. The EISA also gives the Federal Energy Regulatory Commission (FERC) the authority to adopt smart grid standards:

> *"At any time after [NIST's] work has led to sufficient consensus in the [FERC's] judgment, the [FERC] shall institute a rulemaking proceeding to adopt such standards and protocols as may be necessary to insure smart-grid functionality and interoperability in interstate transmission of electric power, and regional and wholesale electricity markets"*[4]

However, as identified by the Government Accountability Office (GAO), FERC does not have the authority to enforce smart grid related standards:

> *"While EISA gives FERC authority to adopt smart grid standards, it does not provide FERC with specific enforcement authority. This means that standards will remain voluntary unless regulators are able to use other authorities—such as the ability to oversee the rates electricity providers charge customers—to enforce them."*[5]

The remainder of this section describes the two major work efforts that have been completed by the CSWG as well as its three-year plan.

[3] NIST Smart Grid Wiki Collaboration Site, http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPAbout. .

[4] Public Law 110 – 140, *Energy Independence and Security Act of 2007*, available at http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/content-detail.html.

[5] GAO Report 11-117, *Electricity Grid Modernization: Progress Being Made on Cybersecurity Guidelines, but Key Challenges Remain to Be Addressed*, available at http://www.gao.gov/products/GAO-11-117.

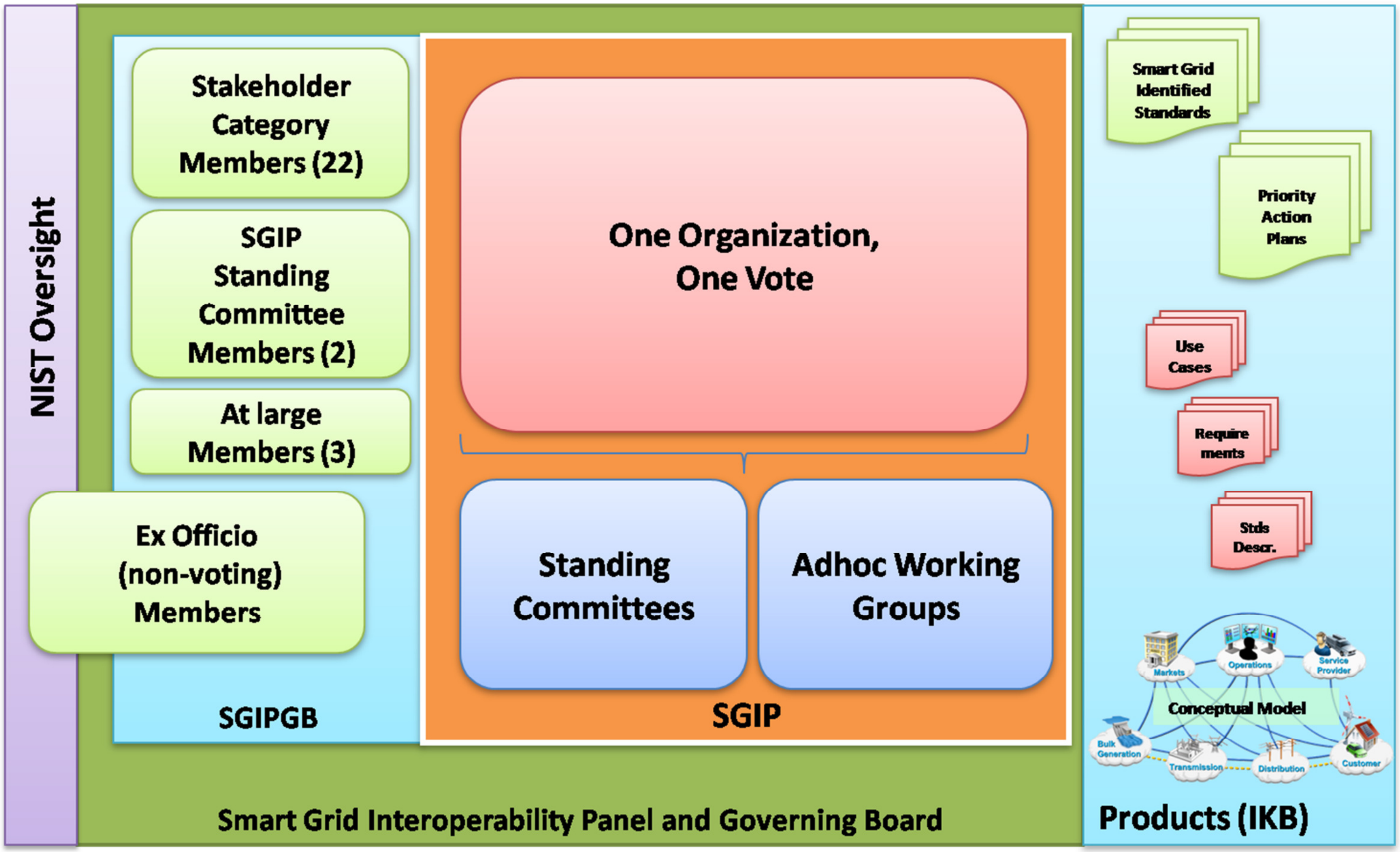

Figure 4.3.1 - NIST Smart Grid Interoperability Panel (SGIP) structure

Guidelines for Smart Grid Cyber Security

The "Guidelines for Smart Grid Cyber Security" (NISTIR 7628) is both a starting point and a foundation for developing a smart grid security strategy. As described in the CSWG 3-Year Plan[6], the first installment of the smart grid cyber security guidelines - NISTIR 7628 v1.0 is:

- An overview of the cyber security strategy used by the CSWG to develop the high-level cyber security Smart Grid requirements
- A tool for organizations that are researching, designing, developing, implementing, and integrating smart grid technologies—established and emerging
- An evaluative framework for assessing risks to smart grid components and systems during design, implementation, operation, and maintenance
- A guide to assist organizations as they craft a Smart Grid cyber security strategy that includes requirements to mitigate risks and privacy issues pertaining to Smart Grid customers and uses of their data.

The NISTIR 7628 defines a smart grid logical reference model by associating smart grid actors to 22 logical interface categories and identifying the interactions between elements in each category. It then presents a set of high-level security requirements, each of these being associated with some or all of the logical interface categories. In addition, the document matches each security requirement to one or more impact levels (i.e. low, moderate, high) resulting from the loss of a component or service.

The organization designing, implementing, or operating smart grid information systems is expected to develop a specific smart grid security architecture and allocate security requirements to each smart grid information system, using the NISTIR 7628 as a starting point. Because of the uniqueness of each smart grid deployment, the organization must take into account particularities of its smart grid systems such as constraints posed by the device and network technologies used, co-habitation with legacy systems, regulations and policies and cost criteria when selecting the smart grid security requirements. In addition, the organization is expected to perform a risk assessment in order to evaluate the impact associated with a cyber security incident affecting the smart grid information systems and to select those requirements that apply to the evaluated impact level for each component of the smart grid information system.

Finally, the NISTIR 7628 was not written in a way in which conformity can be easily assessed or enforced. Instead, as described previously, it is suggested as a toolkit for organizations developing a smart grid security strategy.

Standards Review

In January 2010, NIST published the "Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0"[7]. The report identifies existing technical standards likely to be applicable to a smart grid and prioritizes future action. In addition, in October 2010, NIST advised the FERC that five families of standards fundamental for smart grid interoperability were "ready for consideration by regulators"[8]:

- IEC 61970 and IEC 61968: Provide a Common Information Model (CIM) necessary for exchanges of data between devices and networks, primarily in the transmission (IEC 61970) and distribution (IEC 61968) domains.
- IEC 61850: Facilitates substation automation and communication as well as interoperability through a common data format.

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[6] *CSWG Three-Year Plan*, The Smart Grid Interoperability Panel – Cybersecurity Working Group, April 2011, available at http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/CSWGRoadmap/CSWG_three_year_plan_final_April2011.doc.

[7] NIST SP - 1108, NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0, available at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.

[8] NIST -identified Standards for Consideration by Regulators, Release 1.0, October 6, 2010, available at http://www.nist.gov/public_affairs/releases/upload/FERC-letter-10-6-2010.pdf.

- IEC 60870-6: Facilitates exchanges of information between control centers.
- IEC 62351: Addresses the cyber security of the communication protocols defined by the preceding IEC standards.

In January 2011, FERC held a technical conference on Smart Grid Interoperability Standards[9] to aid determination of whether there is "sufficient consensus" that the five families of standards are ready for the Commission's consideration in a rulemaking proceeding. The statements presented at the FERC technical conference argued that an insufficient number of experts in cyber security have been involved in selecting the standards and that there has not been sufficient consensus.

Emerging Standards

In April 2011, the CSWG published its three-year plan[10] identifying future activities, which are listed in this section:

- Participate in the Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) public-private initiative to develop a harmonized energy sector enterprise-wide risk management process, based on organization missions, investments, and stakeholder priorities.
- Identify cyber and physical vulnerabilities, threats, and the potential impact on the current power grid and augment the NISTIR 7628 high-level requirements to address the combined cyber-physical attacks.
- Expand coordination with the SGTCC to develop guidance and recommendations on smart grid conformance, interoperability, and cyber security testing.
- Update the NISTIR 7628 every 18 months to reflect evolving standards, regulations, threats and risks.
- Continue outreach activities to explain how the NISTIR 7628 can be used.
- Coordinate CSWG activities with federal agencies and industry groups.
- Continue face-to-face meetings for technical working sessions, planning and coordination activities.
- Maintain liaison with Priority Action Plans (PAP) to ensure cyber security is covered where required.

In addition, the following milestones have been proposed for standards review reports:

- Smart Meter / AMI – related standards (Q2 FY11)
- Institute of Electrical and Electronics Engineers (IEEE) 1547 and other standards related to renewable energy sources (Q3 FY11)
- IEEE 1686 and other standards related to substation intelligent electronic devices (IEDs) (Q3 FY 11)
- Demand Response (DR) and HAN-related standards (Q3 FY11)
- Electric vehicle-related standards (Q4 FY11)
- Cyber security-related standards (Q1 FY12)
- New standards developed (Q1 FY11 – Q4 FY13)

Conformity with Evolving Guidelines

For the purpose of identifying conformity with evolving guidelines, OKIOK assessed the conformity of the Duke Energy smart grid with the "Guidelines for Smart Grid Cyber Security" (NISTIR 7628), interoperability standards and best practices.

[9] FERC Technical Conference on Smart Grid Interoperability Standards, January 31, 2011, http://www.ferc.gov/eventcalendar/Files/20110114074853-1-31-11-agenda.pdf.

[10] *CSWG Three-Year Plan*, The Smart Grid Interoperability Panel – Cybersecurity Working Group, April 2011, available at http://collaborate.nist.gov/twiki-sggrid/pub/SmartGrid/CSWGRoadmap/CSWG_three_year_plan_final_April2011.doc.

The NISTIR 7628 was released by NIST in August 2010. Duke Energy has initiated work with a third-party consultancy firm to better understand how the NISTIR 7628 applies to its smart grid environment and how it relates to its existing security guidelines.

NISTIR 7628 Volume 1 – High Level Requirements

This section presents the quantitative evaluation of conformity with the NISTIR 7628 volume 1 – high-level requirements.

Figure 4.3.2 illustrates the families of requirements described in the NISTIR 7628 volume 1 and the number of requirements from each family that are in full, partial or non-conformity. Although the families with longer bars in Figure 4.3.2 do not explicitly represent the importance of one family over another, the longer bars are associated with a greater number of requirements listed for that particular family.

The families with the highest number of requirements in full conformity are [redacted]

The families with the lowest number of requirements in conformity are [redacted]

In order to better visualize the alignment with the NISTIR 7628 requirements we group requirements in full and partial conformity and illustrate the conformity percentages associated with such requirements in Figure 4.3.3.

[redacted]

[redacted]

[redacted]

Finally, Figure 4.3.4 illustrates the percentage of requirements in full or partial conformity compared to those not in conformity based on the category of requirements, i.e., GRC, Common Technical, or Unique Technical.

The detailed list of NISTIR 7628 volume 1 requirements as well as the evaluation of conformity for each requirement is presented in Appendix 3-A – Conformity with the NISTIR 7628.

Figure 4.3.2 – Number of requirements in full, partial and non conformity, per family

Figure 4.3.3 - Percentage of requirements in full, partial and non conformity, per family

Figure 4.3.4 - Percentage of requirements in full, partial and non conformity, per category

NISTIR 7628 Volume 2 – Privacy

This section presents the qualitative evaluation of conformity with the NISTIR 7628 volume 2 – privacy recommendations.

Main Alignment Points:

- Duke Energy has enterprise-wide privacy and procedures in place.
- Notification is provided by the Peak Time Rebate Pilot program informing the consumer that personal consumption baselines will be created.
- The Peak Time Rebate Pilot and the Time of Use Rate Plans are opt-in pilots.
- Evidence of restricting the data collected by the residential electric meter to only that which is necessary, although driven by data transmission costs, was found.
- Evidence of a draft Customer Data Management document including privacy requirements for managing smart grid specific data was found. Although the Customer Data Management document assessed had not been approved by management, it shows Duke Energy's intent of augmenting the current privacy policy and standards to address smart grid data.

Main Gaps:

- The current Personal Information Privacy Policy describes the requirements for protecting the privacy of personal information, for example, health information, social security number, consumer report, and first and last name. The policy does not make reference to energy data collected and processed by smart grid systems as being private or as being protected by the same measures as the Personal Information.
- Evidence of notification being sent to customers, prior to the time of collection describing what data is being collected, the intended use, retention, and sharing of the data, when and why data items are being collected and used without obtaining consent, when and how information may or may not be shared with law enforcement officials, whether new data is being collected, whether there are new information use purposes, and the consumer options was not found.
- Explicit policies, procedures, and guidelines limiting the association of energy data with individuals to only when and where required, de-identifying data when possible, and excluding private information from internal and external research were not found.

NISTIR 7628 Volume 3 – Common Vulnerabilities

This section examines the degree to which the common vulnerabilities listed in the NISTIR 7628 volume 3 are acknowledged by Duke Energy.

Evidence of acknowledgement of the majority of the technical vulnerabilities listed in the NISTIR 7628 volume 3 was found. It is important to note that evidence indicates that Duke Energy employs tools and techniques or has processes and procedures in place that allow it to detect or prevent these vulnerabilities from occurring. However, acknowledgement does not necessarily imply that Duke Energy addressed all occurrences of the vulnerabilities.

The list of vulnerabilities is presented in Appendix 3-C – Evaluation of Common Vulnerabilities Acknowledgement.

Interoperability Standards

This section presents the qualitative evaluation of conformity with interoperability standards.

Main Alignment Points:

- Duke Energy currently implements or follows several open standards and standard families:

    [redacted]

    [redacted]

    [redacted]

[redacted]

- Duke Energy acknowledges the importance of the NIST SGIP and the selection by NIST of the five smart grid interoperability standard families: IEC 61970, IEC 61968, IEC 61850, IEC 60870 and IEC 62351.
- Architecture guidance to give preference to solutions implementing the Common Information Model (CIM) related standard is in place.
- Documentation proposing the implementation of open standards facilitating interoperability at the network, syntactic and semantic levels between the various smart grid components was found.

Main Gaps:

- Formal documentation of management commitment for ensuring the adoption of interoperability standards was not observed.
- Evidence of the five families of standards selected by NIST (IEC 61970, IEC 61968, IEC 61850, IEC 60870 and IEC 62351) being part of Smart Grid solutions requirements was not found.
- A roadmap for adopting interoperability standards was not found.

Security Best Practices

This section presents the qualitative evaluation of conformity with industry security best practices.

Main Alignment Points:

[redacted]

Main Gaps:

[redacted]

Risks of Nonconformity

For the purpose identifying risks of nonconformity with emerging standards, OKIOK analyzed the conformity of the current Duke Energy smart grid implementation with the NISTIR 7628 security requirements versus the potentiality of a security breach of associated with each of these requirements.

Figure 4.3.5 illustrates all of the security requirements assessed from the NISTIR 7628. The horizontal axis represents the level of conformity of Duke Energy smart grid with the requirements assessed. The leftmost column in Figure 4.3.5 represents Full Conformity and is illustrated in green signifying that there is no significant risk associated with the requirements listed in this column. The vertical axis represents the impact on the potentiality of a security breach. The upper row represents a high potentiality, which translates to an immediate impact on the probability that a security breach will occur. For this reason, the upper rightmost cell is illustrated in red to represent the highest risk.

For the detailed results of conformity with the NISTIR 7628 requirements the reader is invited to see Appendix 3-A – Conformity with the NISTIR 7628.

Similarly, the detailed results of the impact on the potentiality of a security breach to occur for the NIST 7628 requirements are presented in Appendix 3-B – Potentiality of a Security Breach.

In the rest of this section the families of requirements that are associated with a high risk are analyzed. The following families were found to have [redacted] of requirements in non-conformity and with high potentiality of a security breach:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

For each family identified above, risk scenarios that illustrate the potential consequences of a security breach are presented. Note that the risk scenario presented is not exhaustive and variations of the scenario or other scenarios might be feasible. Finally, for each family a high level recommendation describing the type of countermeasure that could potentially be put in place to mitigate the risk is proposed.

For a detailed quantitative description of the percentage of requirements in full, partial or non-conformity in each family as well as a mapping with the evaluation of the potentiality of a security breach see Appendix 3-D – Potentiality of a Security Breach vs. Conformity.

Figure 4.3.5 - Mapping of the security requirements with the conformity level and the potentiality of a security breach

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5 OPERATIONAL BENEFITS

5.1 Introduction

The Staff asked MetaVu to evaluate and assess the operational benefits from smart grid implementation. Staff defined these as benefits that have either accrued to the benefit of Duke Energy or may reasonably be expected to accrue to Duke Energy in the future. Staff provided information on Duke Energy's original smart grid business case to MetaVu on a confidential basis. MetaVu used the original business case as a starting point for its assessment.

Thirty Operating Benefits were identified by Duke Energy in its original business case. Several of these benefits were consolidated into others, some were determined to be out of scope as defined by Staff, and a few new benefits were identified, resulting in a total of twenty five Operating Benefits evaluated by MetaVu and presented here. Each benefit was classified into one of four saving types based on how the benefit is likely to be recognized in existing rate making processes. These savings categories include:

- Avoided Operations and Maintenance Cost
- Avoided Fuel Cost
- Deferred Capital
- Increased Revenue.

Several benefits identified by Duke Energy Ohio in the original business case as customer benefits (such as time-differentiated rate and reliability) or societal benefits (such as environmental) were defined as out of scope for the Audit and Assessment.

The Operational Benefits section begins with a description of the methodology used to estimate the Net Present Value or NPV of the twenty five Operating Benefits. A "Benefits Summary" presents analyses of synthesized Operational Benefit estimates. Finally, each of the twenty five Operating Benefits is presented individually including:

- The estimated 20-year net present value of the individual benefit and the percentage of the total that the Benefit represents
- Savings Category to which the benefit relates
- Background on how the benefit results from smart grid capabilities
- The drivers that most significantly impact the size of each benefit
- Modeled economic benefits by year until steady state is achieved

Charts are used to illustrate key points. Supporting details and methodologies are available in the Appendix as indicated.

5.2 Methodology

MetaVu completed multiple calculations to evaluate and forecast potential benefits from Duke Energy's Ohio smart grid deployment. In 2008, Duke Energy provided a business case outlining the various benefits anticipated from its Ohio Smart grid deployment. MetaVu considered the business case and approaches employed by Duke Energy to calculate various benefits in light of other MetaVu experience and available information, including:

- MetaVu's experience in evaluating Xcel Energy's SmartGridCity™ demonstration project
- Measurement frameworks and performance benchmarks from the Electric Power Research Institute
- American Recovery and Reinvestment Act smart grid evaluation metrics
- Information from the regulatory dockets of other utilities pursuing smart grid projects (including Oklahoma Gas and Electric and Baltimore Gas and Electric).

After considering such inputs MetaVu developed revised versions of benefit calculations to be applied to the Ohio smart grid deployment.

To better understand how calculations could be accurately applied and to validate various calculation inputs, a series of data requests were submitted to Duke Energy. These data requests resulted in formal responses and meetings with Subject Matter Experts (SMEs). Data captured from data request responses and SME meetings allowed MetaVu to accurately estimate and forecast smart grid benefits. As data was provided to MetaVu for analysis, additional data and meetings with SMEs were requested to refine and supplement previously delivered information and provide a robust understanding of the Duke Energy smart grid's capabilities.

After evaluating data request responses, SME meeting notes, and supplemental information, MetaVu forecast annual benefits from 2009 to 2028 (20 years) to estimate the NPV of each. For some larger or more highly variable benefits, MetaVu calculated high case, base case, and low case estimates. Results presented in this report are base case estimates unless otherwise indicated.

5.3 Benefits Summary

In total, MetaVu estimated the NPV of smart grid benefits at $382.8 million. A series of summary tables and charts are presented to facilitate conclusions about detailed Operational Benefit estimates:

- Summary of Base Case Estimate Data by Operational Benefit
- Chart of Relative NPV Size by Operational Benefit
- Low-, Base-, and High-Case NPV Comparison Chart
- Chart of NPV by Savings Category
- Chart of NPV by Investment Type (AMI vs. DA)
- Operational Benefit Ranking by NPV Size Chart

Figure 5.3.1 lists the Operating Benefits and details the 5-year total, 20-year total, and 20-year NPV of each.

Figure 5.3.2 indicates the relative size of NPV by Operational Benefit.

Figure 5.3.3 illustrates the summary of benefits in high, mid, and low cases. Some benefits were calculated with varying assumptions, providing low-, base- and high-case scenarios to provide the reader insight on the possible variances of the benefit calculation.

Figure 5.3.4 represents the breakdown of benefits by accounting categories Avoided O&M Cost, Avoided Fuel Cost, Deferred Capital, and Increased Revenue. It should be noted benefits 4 and 13 create value for two different categories.

Figure 5.3.5 compares the total benefits provided by the Distribution Automation (DA) and Advance Metering Infrastructure (AMI) systems.

Figure 5.3.6 sorts all the benefits by value based total 20-year NPV totals.

Figure 5.3.1 Summary of Base Case Estimate Data by Operational Benefit

Benefit Number	Infrastructure Category	Benefit	Savings Category	5-Year NPV BASE	20-Year Total BASE	20-Year NPV BASE
1	AMI	Regular meter reads	Avoided O&M Cost	$ 3.75	$ 125.28	$ 49.86
2	AMI	Off-cycle / off-season meter reads	Avoided O&M Cost	$ 8.33	$ 123.43	$ 53.96
3	AMI	Remote meter diagnostics	Avoided O&M Cost	$ 0.74	$ 16.07	$ 6.53
4 & 5[11]	AMI	Power theft (4) - Recovery Costs (5)	Increased Revenue	$ 0.92	$ 19.47	$ 7.94
6	AMI	Meter operations – Avoided capital costs	Capital Deferment	$ 2.03	$ 40.28	$ 16.58
7	AMI	Meter operations – Decreased annual expenses	Avoided O&M Cost	$ 0.29	$ 5.91	$ 2.43
8	AMI	Meter accuracy improvement	Increased Revenue	$ 0.98	$ 20.87	$ 8.51
9	AMI	Meter Salvage Value	Increased Revenue	$ 0.45	$ 0.93	$ 0.66
10	AMI	Outage Detection	Avoided O&M Cost	$ 0.07	$ 1.44	$ 0.59
11	AMI	Outage Verification	Avoided O&M Cost	$ 0.64	$ 12.68	$ 5.22
12	AMI	Outage – Incremental Revenue	Increased Revenue	$ 0.62	$ 14.96	$ 5.64
13	DA	24/7/365 System Voltage Reduction Strategy	Mostly Avoided Fuel Cost	$ 7.48	$ 389.92	$ 155.57
14	DA	Power Shortage Voltage Reduction	Capital Deferment	$ 0.07	$ 2.15	$ 0.86
15	DA	Continuous Voltage Monitoring	Avoided O&M Cost	$ 0.06	$ 4.37	$ 1.71
16	DA	VAR Management	Capital Deferment	$ 0.87	$ 22.54	$ 9.26
17	DA	Asset Management	Capital Deferment	$ -	$ 3.00	$ 1.89
18	DA	System Fine-tuning	Mostly Avoided Fuel Cost	$ 0.03	$ 18.74	$ 7.17
19	DA	Capacitor Inspections	Avoided O&M Cost	$ 0.05	$ 3.57	$ 1.39
20	DA	Circuit Breaker Inspections	Avoided O&M Cost	$ 0.10	$ 1.86	$ 0.77
21	AMI	Call center efficiency	Avoided O&M Cost	$ 0.14	$ 2.75	$ 1.13
22	AMI	Increase in safety	Avoided O&M Cost	$ 0.10	$ 2.28	$ 0.93
23	AMI	Billing savings – Shortened billing cycle	Avoided O&M Cost	$ 0.12	$ 1.78	$ 0.74
24	AMI	Vehicle Management	Avoided O&M Cost	$ 1.22	$ 24.83	$ 10.21
25	DA	Fuel Cost Reduction through VAR reduction	Avoided Fuel Cost	$ 0.18	$ 9.31	$ 3.73
26	DA	Wholesale sales due to freed-up capacity	Increased Revenue	$ 0.05	$ 81.54	$ 29.52
TOTAL				$ 29.29	$ 949.96	$ 382.79

[11] Benefits 4 & 5 have been combined as one benefit.

Figure 5.3.2 Chart of Relative NPV Size by Operational Benefit - Base case in millions

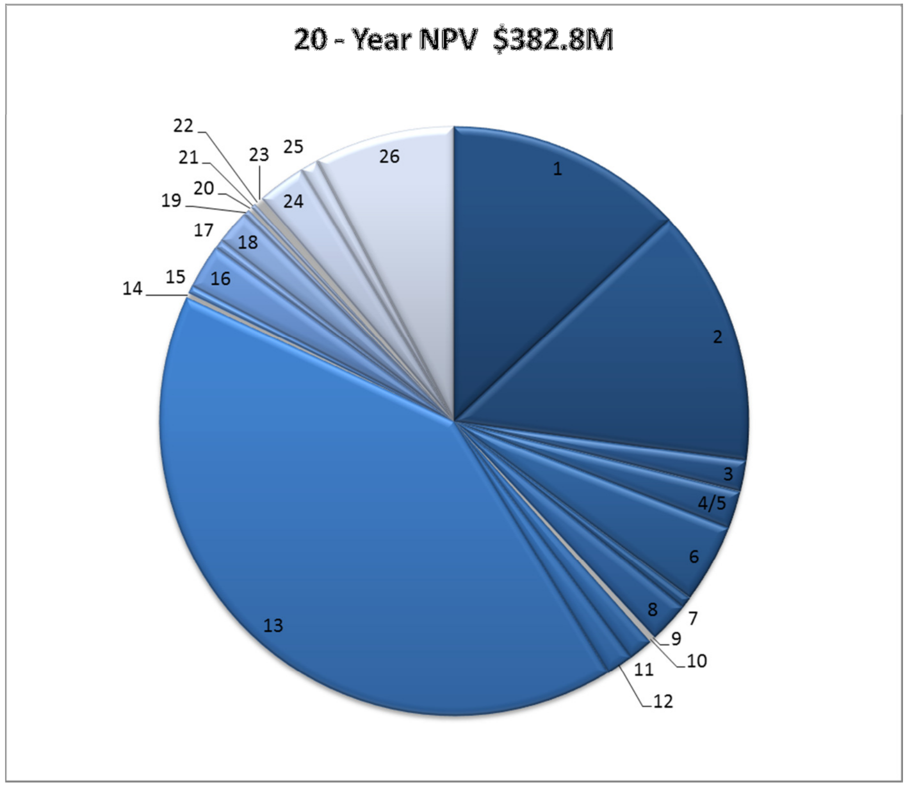


Figure 5.3.3 Low-, Base-, and High-Case NPV Comparison Chart

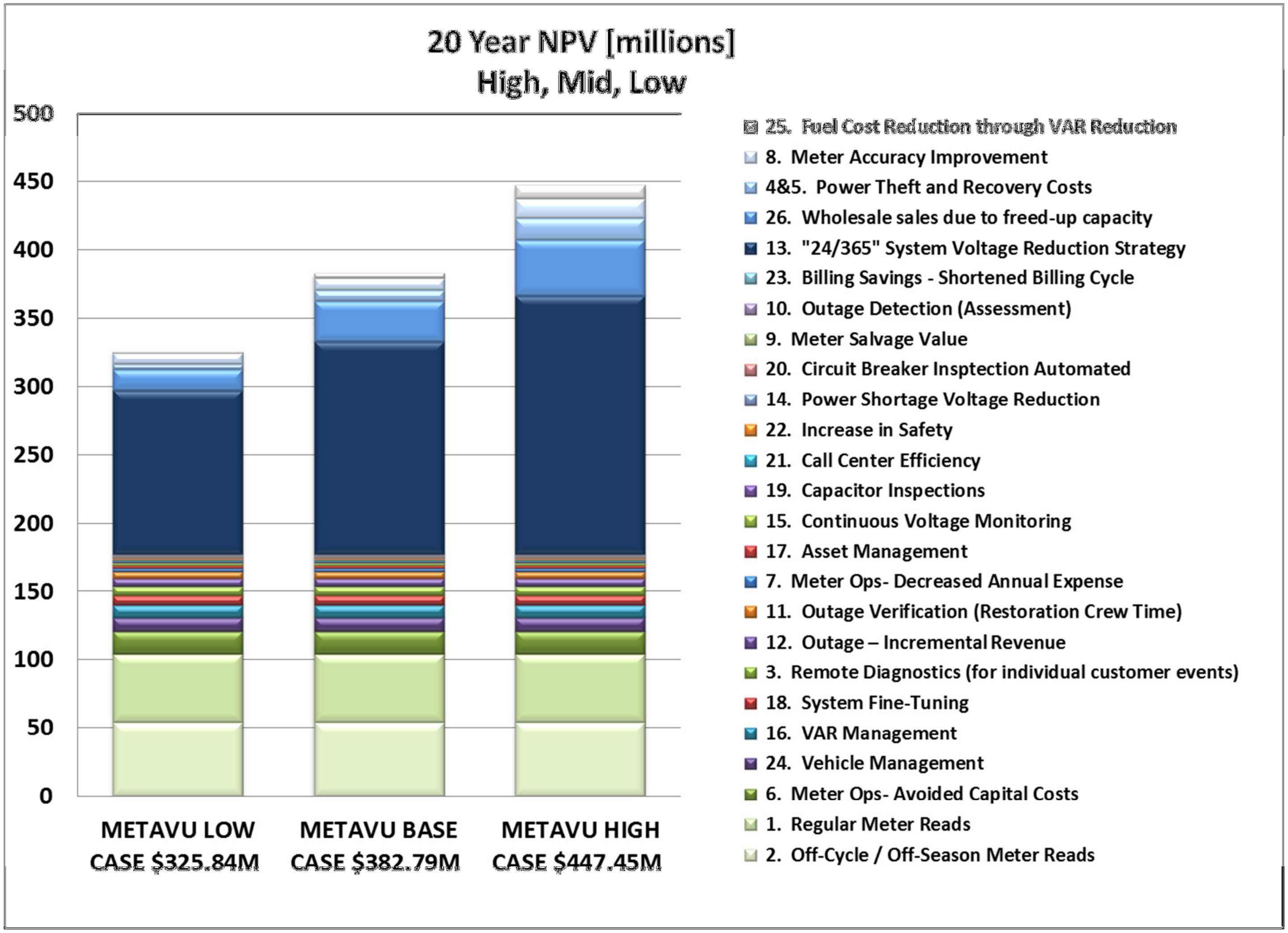


Figure 5.3.3 illustrates the summary of benefits in low, base, and high cases. Some benefits were calculated with varying assumptions, providing low, base, and high scenarios to provide the reader insight on the possible variances of the Operational Benefit estimates.

Figure 5.3.4 Chart of NPV by Savings Category

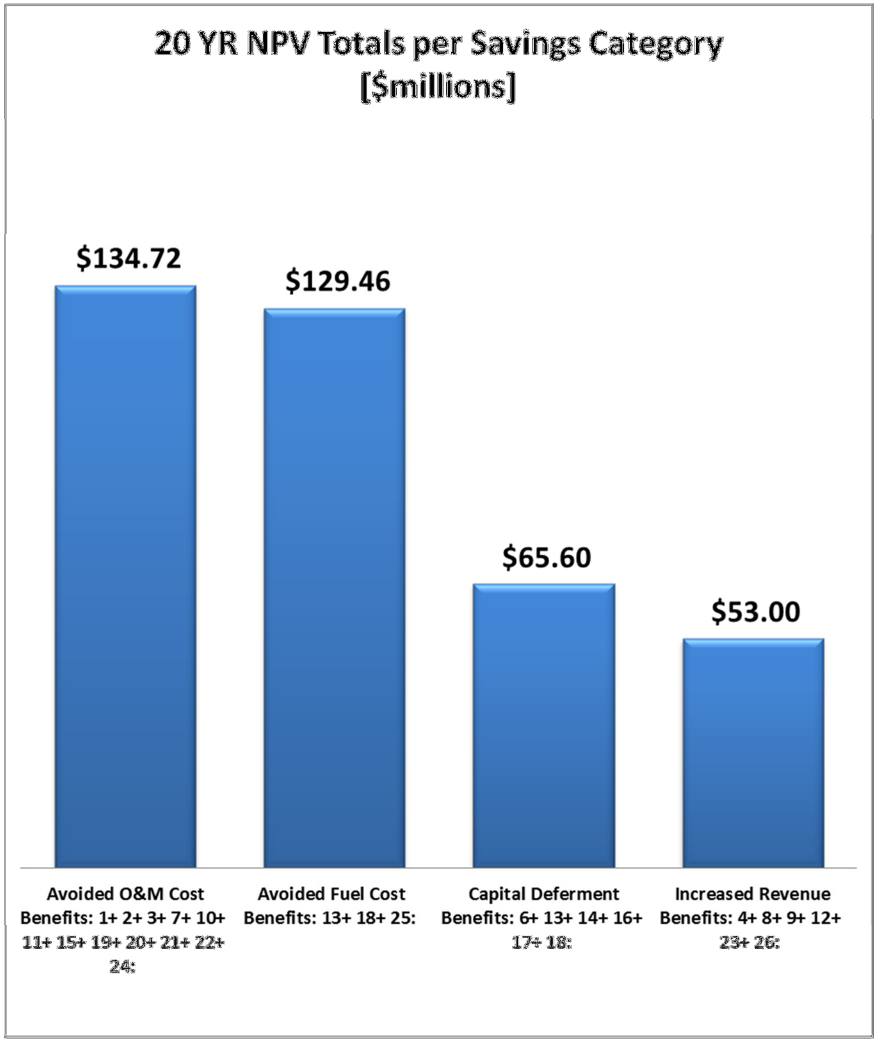


Figure 5.3.4 represents the breakdown of benefits by Savings Categories: Avoided O&M Cost, Avoided Fuel Cost, Deferred Capital and Increased Revenue. Note that A) Benefits 13 and 18 create value for two different categories; B) Lost Margins have been netted out of Benefit 26; and C) Theft recovery costs have been netted out of Benefit 4

Figure 5.3.5 Chart of NPV by Investment Type (DA = Distribution Automation; AMI = Advanced Metering Infrastructure)

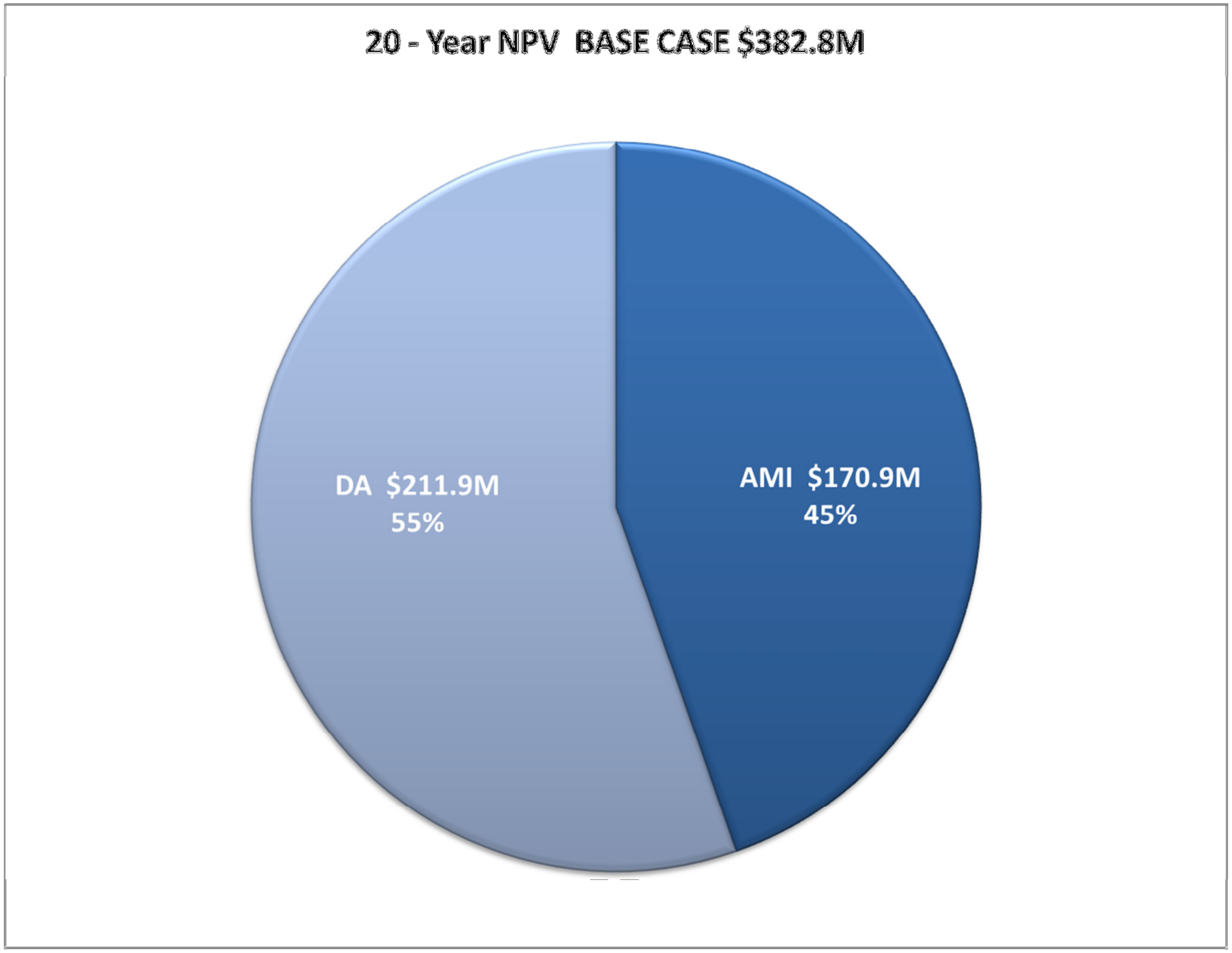


Figure 5.3.5 compares the total benefits provided by the Distribution Automation (DA) and Advanced Metering Infrastructure (AMI) investments. Note that outage-related benefits are provided by a combination of DA and AMI.

Figure 5.3.6 Operational Benefit Ranking by NPV Size

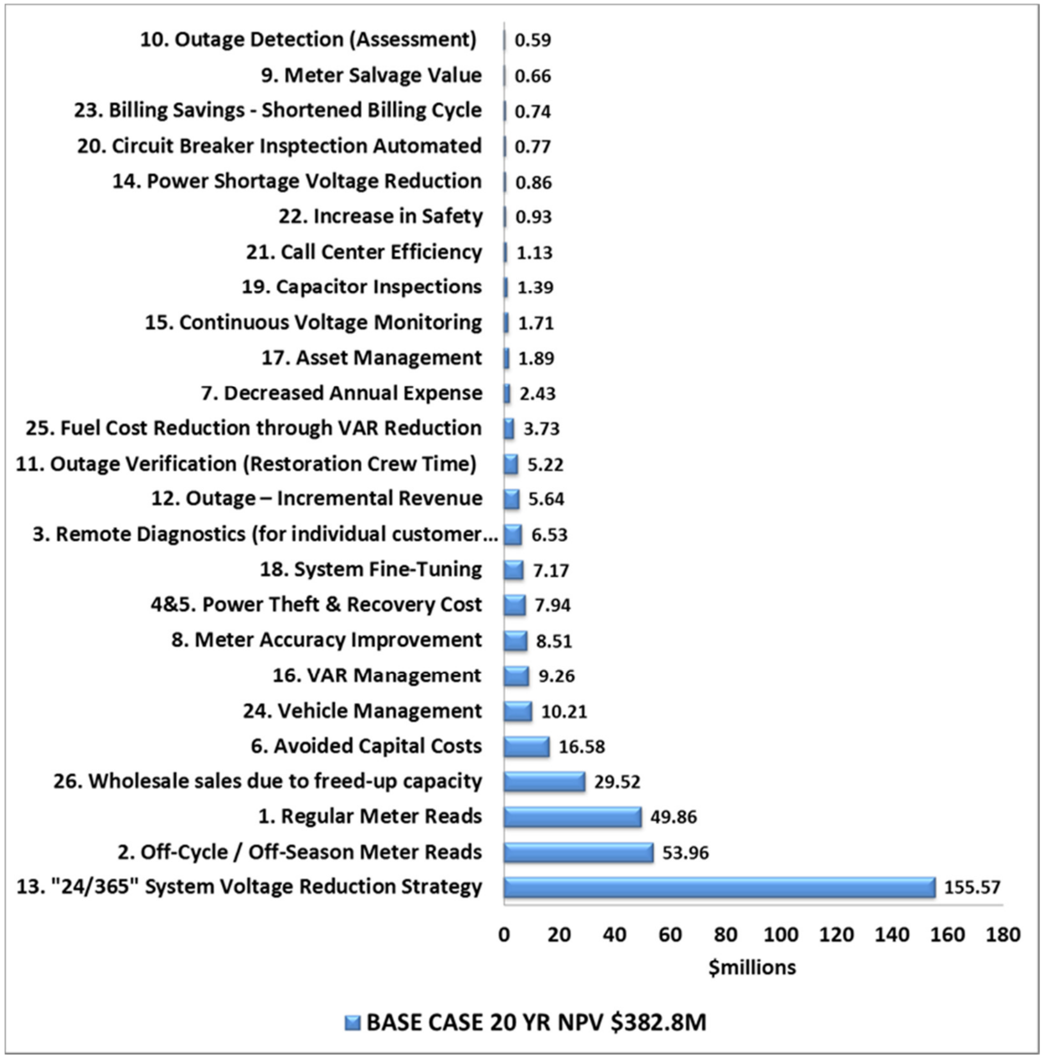
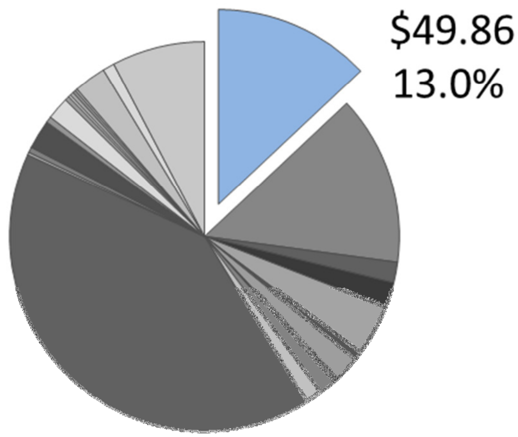


Figure 5.3.6 ranks Operational Benefits by base case 20-year NPV.

5.4 Findings

Regular Meter Reads (Benefit 1)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

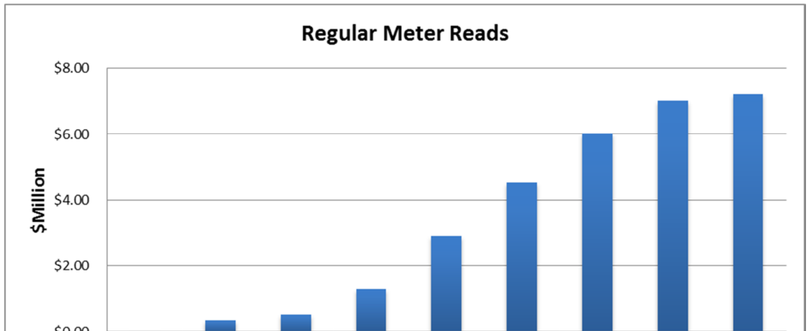
- AMI technology will eliminate the majority of on-cycle manual Meter Reading as smart meters are deployed. The benefit value consists of a labor cost reduction from Meter Reading staff. The benefits from reducing Meter Reading vehicles is captured in benefit number 25.
- Duke Energy in Ohio has traditionally employed Meter Readers to manually read meters on a monthly basis. This process consists of individuals walking from house to house to capture electric and gas meter data with handheld equipment. Meter Readers then provide meter data to the utility for billing purposes. With the deployment of smart meters, metering data is communicated via a wireless network to the utility. As data is sent directly to the utility, the need for most manual meter reads will be eliminated with corresponding reductions to Meter Reading staff. It is anticipated some staff will be required to occasionally read meters manually for potential failure of smart meters or smart meter communications and for periodic gas safety checks of gas meters.
- Relative to other U.S. geographies, manual meter reading is particularly expensive in Duke Energy's Ohio territory as a significant number of meters are located within customers' premises. To access the meters, Meter Readers may need to schedule and reschedule appointments which is resource intensive, cumbersome, and inconvenient to customers.
- Electric smart meters capture energy usage data on a 15 minute basis. Communications nodes placed on distribution transformers collect meter data. Wireless data transmitters are placed upon traditional gas meters and regularly provide gas readings to the same communication nodes. The communications nodes transmit electric and gas meter data wirelessly on a daily basis to Duke Energy for bill processing.
- It is anticipated the Meter Reading department that covers Duke Energy's Ohio footprint will be reduced. Approximately half of remaining Meter Reader time will be allocated to meter reading activities. The other half will address gas meter safety inspections which regulatory rules require every 3 years.
- Smart meter data provides granular data that can be accessed through a "Customer Portal", providing customers with insights on usage, including historical analysis and usage compared to weather temperatures.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- Annual meter reading labor costs for Duke Energy Ohio
- Meter Reader reduction resulting in meter reading route consolidation and Full-Time-Equivalent (FTE) reduction
- Labor inflation rates

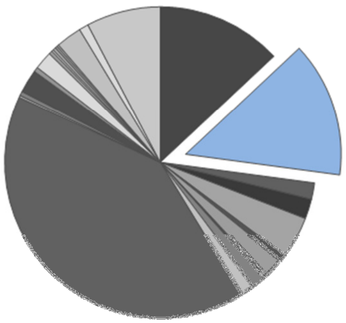
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.35	$0.54	$1.31	$2.93	$4.54	$6.02	$7.02	$7.23

Off-Cycle/Off-Season Meter Reads (Benefit 2)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

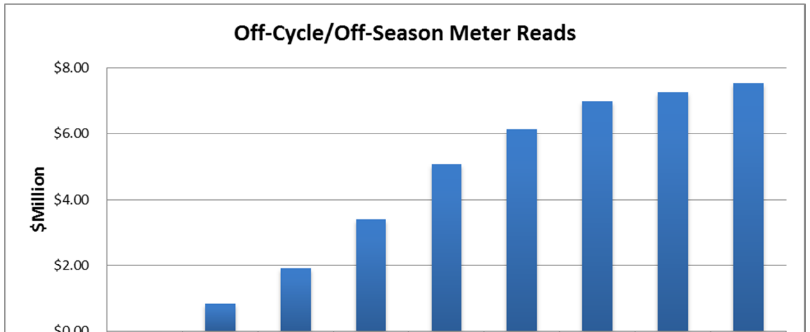
- AMI technology will eliminate a portion of the meter reads not associated with regular monthly reads. These reads, classified as Off-Cycle / Off-Season Reads, are more accurately defined as "Meter Orders". Meter Orders include meter reads outside the typical billing cycle such as move-ins and move-outs, customer requested service additions, and cancellations. The feasibility of remote disconnects for non-payment were also evaluated as providing potential value. This benefit measures the labor costs associated with these meter order activities.
- Duke Energy in Ohio has traditionally employed field technicians to physically read meters outside of the standard billing cycle window, generally when customers move-in or move-out of a residence. In addition, customers often request energy to be turned on or shut off, which requires a field technician to physically turn off service. These voluntary Meter Orders can now be conducted remotely with smart meter deployment. If a customer calls to indicate they are moving to or leaving a premise, the call center can arrange a remote meter read for that date. For activation or deactivation of service (often due to move-ins or move-outs), a customer can call and indicate when service should be turned on or off remotely. Remote shut off of service is not available for gas meters for safety reasons.
- Smart electric meters and gas modules have the capability to be read through a real-time meter read. This allows the utility to conduct an instantaneous read outside of the standard billing cycle. Smart electric meters have remote connect/disconnect capabilities at the customer request that allow the utility to activate or deactivate service without sending an individual to do it manually. (Note that gas meters do not have remote connect/disconnect capabilities and field technician visits are required.)
- Traditionally, service disconnects due to non-payment have been completed physically by a field technician. It was originally anticipated that remote disconnect capabilities could create value by not deploying a field technician to manually disconnect the electric meter for reason of non-payment. However, regulations require a Duke Energy employee to physically notify the customer of an upcoming involuntary electricity disconnect by leaving a door hanger at the customer's premise. This regulation requiring a person to visit the premise prior to disconnecting service eliminates the benefit for remote disconnects due to non-payment.
- Benefits for non-payment remote disconnects could be achieved if changes to current regulatory rules were enacted. Reductions in uncollectible account write-offs might also be available.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- Annual Meter Order labor costs for Duke Energy Ohio
- Reductions in FTE positions
- Regulatory requirements for disconnections of service
- Labor inflation rates
- Vehicle and fuel costs

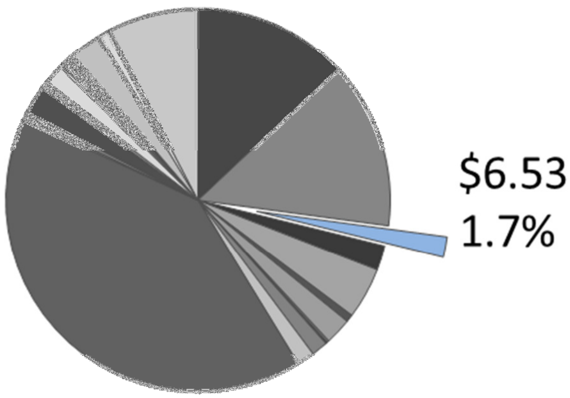
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.84	$1.92	$3.41	$5.07	$6.14	$6.98	$7.25	$7.52

Remote Meter Diagnostics (Benefit 3)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

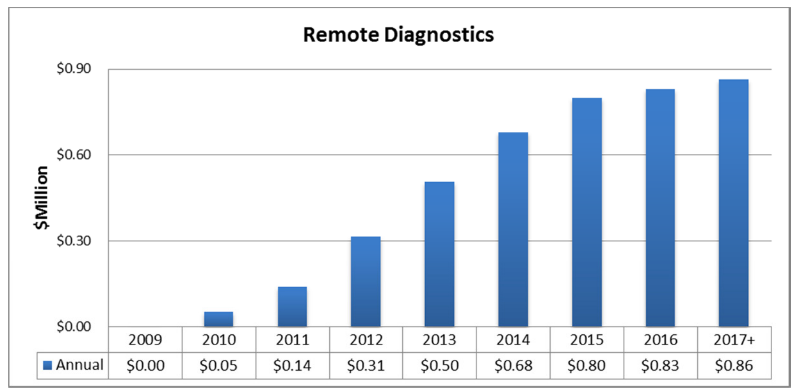
- With the ability to conduct real-time remote diagnostics of smart meters, smart grid technology provides system dispatchers with the ability to reduce trouble dispatches that end up being unnecessary when the problem is determined to exist on the customer's side of the meter. A reduction in the number of these dispatches translates into a reduction of labor needed to address these calls.
- With traditional meters, Duke Energy did not have the capability to understand if a customer issue was on the utility or customer-side of the meter until after a field technician physically investigated the problem. If the issue was on the customer-side, no further action was required by the utility and the customer would need to contact an electrician. AMI technology allows for the utility to conduct a real-time remote diagnostic to determine if the meter is operating normally. If the meter is receiving voltage, no field personnel are sent to investigate.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

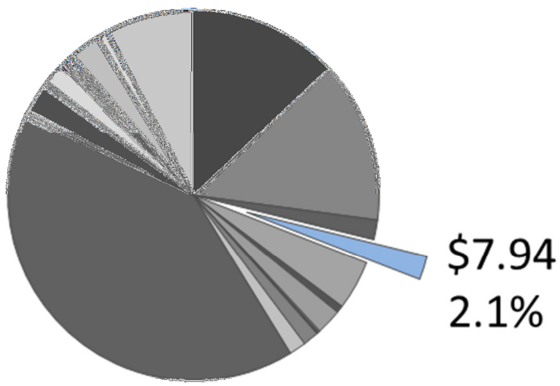
- The deployment rate of smart electric meters
- Annual cost to investigate individual customer events
- Reduction of labor hours dedicated to investigating customer-side issues
- Labor inflation rates can fluctuate over the years which could impact the 20-year savings
- Vehicle and fuel costs

Modeled Economic Benefits



Power Theft/Theft Recovery Costs (Benefits 4 and 5)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

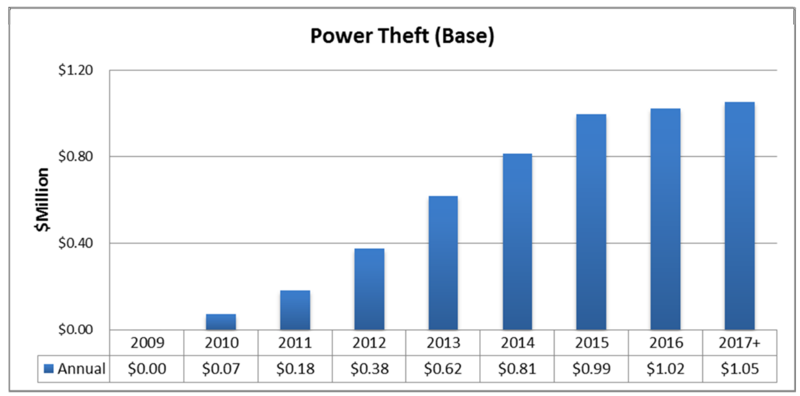
- Power theft in the United States has been hard to quantify, and in the literature it has been assumed to be 0.5-1.0 percent of any utility's overall revenue.
- Traditional meters do not offer capabilities to detect tampering, meters installed up-side down, or intentionally mis-wired or bypassed meters.
- Electric smart meters can generate tampering alarms and detect mis-wiring. VEE processes employed by Duke Energy take advantage of smart meters' 15 minute interval data availability to monitor and track consumption registration on meters to identify possible theft. By adding investigation and prosecution process steps, a reduction in theft will result in lower losses and increased revenue.
- By the end of 2009 Duke Energy had replaced 8% of all meters classified as residential or commercial/industrial <500kW. In 2010, an increase in revenue due to power theft from Electric smart meters was quantified and realized in Ohio. The increased revenue gives an early indication that power theft from electric smart meters is in the range 0.25-0.5 percent of overall revenue, assuming VEE processes are detecting and reducing previously unbilled/stolen energy by 50 percent.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

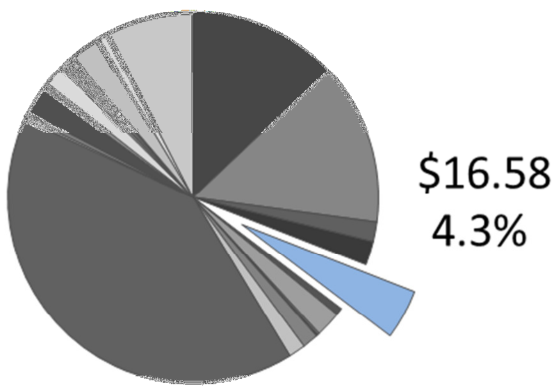
- Estimated Power Theft as a percentage of overall revenues
- Estimated Reduction in Power Theft due to smart grid
- Incremental Investigation Cost. (Source: United Illuminating, eSource conference presentation, September 2010. $15 billed for every $1 spent on investigation, less 55% uncollectible.)

Modeled Economic Benefit



Meter Operations Capital (Benefit 6)

$ NPV in millions/% of total benefits



Savings Category – Deferred Capital

Background on Benefit

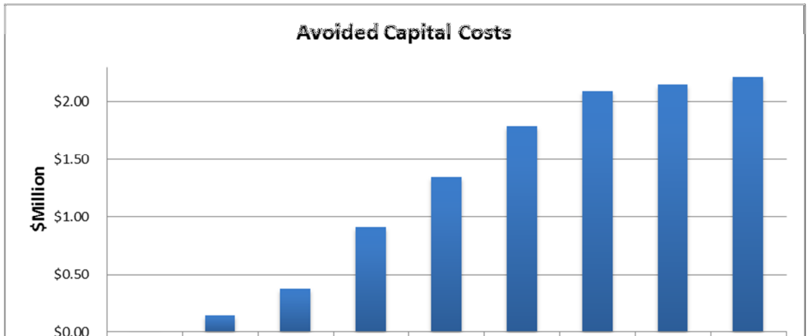
- With the deployment of AMI technology, capital costs associated with the replacement of traditional meters and related equipment will be significantly reduced.
- Without AMI deployment, traditional meters, and other related equipment, such as handheld devices, would have to be replaced over time resulting in regular capital costs. As penetration of smart meters increases, the need to replace traditional meters and other manual meter reading equipment will decrease significantly.
- Smart meters do not require the use of equipment related to manual meter reads such as handheld devices, resulting in reduced costs.
- It must be noted that smart meters will also need to be replaced after life cycle completion, estimated to be 20 years.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- The meter and equipment purchase and installation labor budgets for Duke Energy Ohio
- Labor and material inflation rates

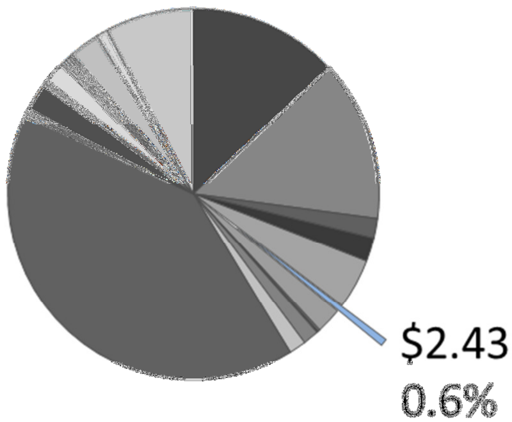
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.14	$0.37	$0.91	$1.34	$1.79	$2.09	$2.15	$2.22

Meter Operations Costs (Benefit 7)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

- AMI technology will utilize smart meters which will not require the same testing and refurbishment as traditional meters. Instead, smart meters will require very little testing or refurbishment as they will be replaced upon failure. This will reduce labor costs in the meter operations department.
- Traditional meters and associated handheld equipment decrease in accuracy over time, requiring routine testing and occasional refurbishment to function properly. Traditional meters may speed up or slow down over time, impacting the integrity of readings.

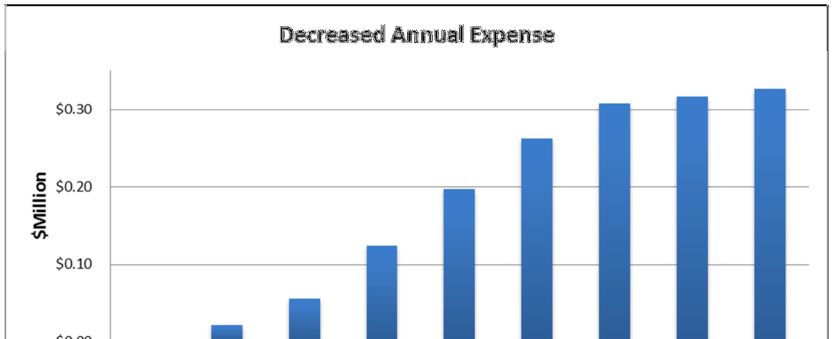
Due to their digital nature, smart meters do not require regular testing to ensure accuracy. In addition, refurbishment is not required of smart meters as they generally maintain accuracy until failure, at which time they will be replaced.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- Annual meter testing costs
- Annual meter refurbishment costs
- Labor inflation rates

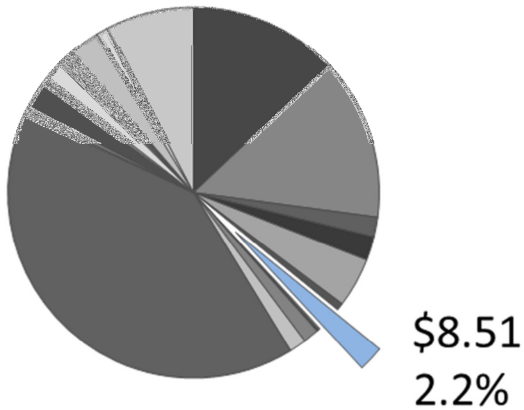
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.02	$0.05	$0.12	$0.20	$0.26	$0.31	$0.32	$0.33

Meter Accuracy Improvement (Benefit 8)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

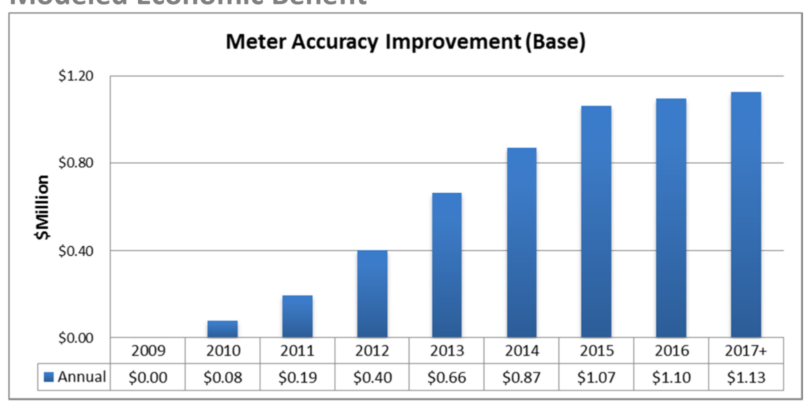
- The meter tests conducted as part of this project (see the Operational Audit section) indicated that Duke Energy Ohio's traditional meters, on average, register a slightly lower energy use reading than actual consumption. This can be attributable to:
  - Increased friction between moving parts over time
  - Sensitivity to tilted (not level) installations
  - Uncorrected temperature-related errors in the traditional meter instrumentation
- The electric smart meters do not have moving parts and can correct temperature-related error with simple algorithms, making them inherently more accurate.
- The meter tests indicated that the electric smart meters:
  - Will register energy use within the manufacturer's specified tolerance, which is far more accurate than traditional meters
  - Do not suffer from under-reported usage.
- Because the traditional meters under-report usage on average, replacing them with more accurate smart meters will result in increased billings and collections.
- The meter tests indicated that an average electric smart meter was expected to increase accuracy by 0.06-0.065% over that of an average traditional meter.
- With weighting, this translates into increased billed revenue of 0.17-0.18% (after weighting to create "usage over time" estimates from "point-in-time" meter accuracy tests).
- A Duke Energy study attributes 0.3-0.35% revenue gains for deployed electric smart meters in 2010 to improved accuracy.

Benefit Drivers

"Percent Accuracy Improvement" is the largest single driver of this benefit. Conservatively weighted (0.17%), realistically weighted (0.18%) and Duke study (0.30%) estimates were used to calculate revenue increases in low case, base case, and high case values, respectively.

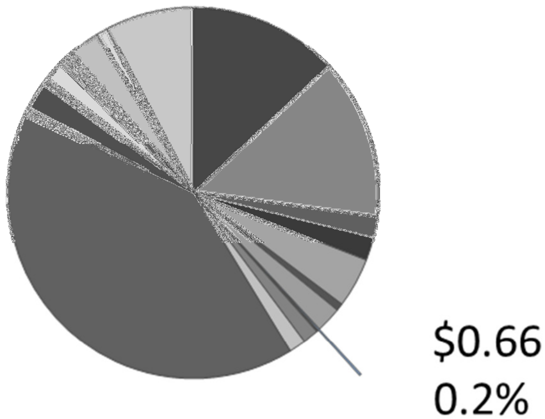
Meter Deployment Rate is also an important benefit driver.

Modeled Economic Benefit



Meter Salvage Value (Benefit 9)

$ NPV in millions/% of total benefits



Savings Category – Increased Revenue

Background on Benefit

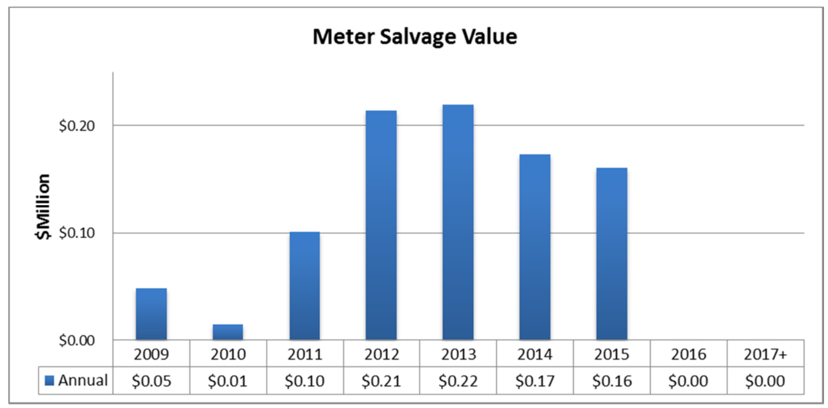
- For traditional meters exchanged for smart meters, those that cannot be refurbished and redeployed within Duke Energy's footprint will be salvaged. Salvaging meters for scrap metal will increase Duke Energy revenues.
- As gas modules are deployed there are instances in which the entire gas meter must be replaced. Gas meters removed and salvaged cannot be considered a smart grid related benefit according to Staff, and therefore were not considered in this benefit calculation.
- This benefit begins to accrue after the first year of deployment and will end after all smart meters have been deployed.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

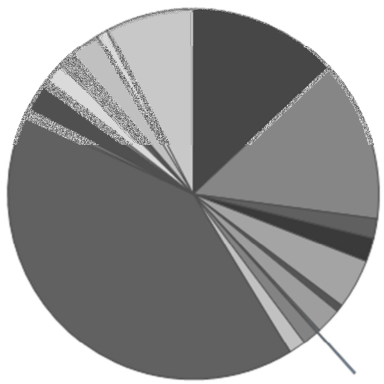
- The rate at which smart electric meters are deployed.
- The rate of traditional meter refurbishments. As more refurbished traditional meters are redeployed there is the possibility of saturation. Duke Energy may not require additional refurbished traditional meters as more smart meters are deployed. Therefore, fewer refurbished meters will result in an increase in the level of meters salvaged.
- The salvage value of meters and inflation of materials during the deployment period.

Modeled Economic Benefits



Outage Detection (Benefit 10)

$ NPV in millions/% of total benefit



Savings Category – Avoided O&M Cost

Background on Benefit

- The deployment of AMI and DA technology provides the capability to detect the extent of customer outage, with sensing technology and on-demand readings of smart meters. This allows assessors to correctly determine which areas of an outage are restored and which are still experiencing an outage. This benefit reduces assessor labor hours.
- During storms that cause outages, a Storm and Natural Disaster plan is activated. Duke has defined 4 severity levels:
  - Level 1: Various localized damage
  - Level 2: Moderate damage over large area or heavier damage over small area
  - Level 3: Heavy damage over large area or extensive damage over small area
  - Level 4: An overwhelming amount of damage over major or all service territory anticipated to take several days to fully restore
- Outages caused by "Level 1 storms" or with "Level 1 Severity" are handled by distribution operators. For levels 2, 3 and 4, when the number of customers and number of storm outage cases escalates and becomes unmanageable for the distribution operator, field assessors are activated.
- Assessors investigate and call in from the field to assign appropriate restoration resources. Historically, many trouble tickets relate to areas where service has already been restored.
- Electric smart meters have remote diagnostic capabilities that can be used to avoid "already restored" tickets and reduce assessor labor.
- As illustrated in figure 10.1 all assessors' combined number of hours per year is estimated to be reduced by 20 percent.
- In addition, smart grid DA equipment such as circuit breaker relays and electronic reclosers can calculate approximate fault locations, which may further reduce the time spent in assessment.
- Duke Energy's IT-plans indicate that the outage management system (OMS) will fully integrate data from interruption equipment, line sensors, electric smart meters and GIS, and will be able to automatically map out outages and pinpoint fault locations. This will accelerate the scouting process and effectively reduce/improve the total customer outage time. Duke has already deployed and integrated a significant amount of DA hardware. In addition, a project charter has been approved that would marry electric smart meter data into the OMS for additional improvements if implemented.

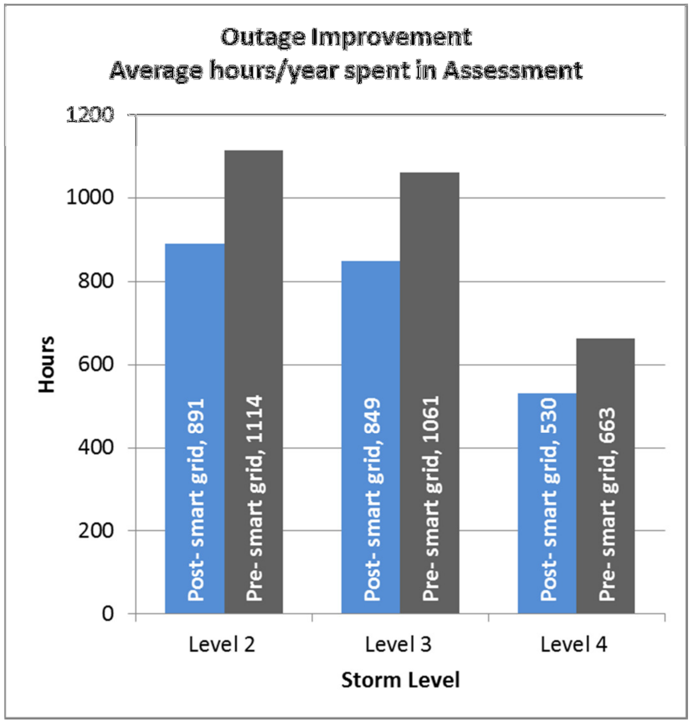
Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

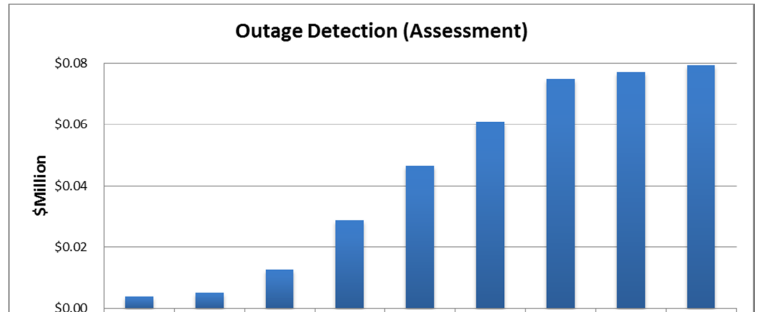
- Average Annual Number of Outage Events and Duration
- Average Number of Assessors per Outage Event

- Percent of Outage Spent in Assessment
- Cumulative Meter Deployment Rate
- Percent Reduction in Assessment Time
- Hourly Labor Rate and Labor Rate Inflation

Fig.10.1 Reduction in Assessors' combined hours



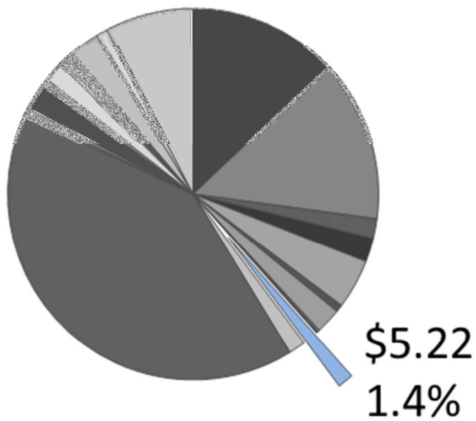
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.01	$0.01	$0.03	$0.05	$0.06	$0.07	$0.08	$0.08

Outage Verification (Benefit 11)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M cost

Background on Benefit

- During storms and OCB/recloser failures, it is critical for maintenance / outage crews to quickly identify and verify failure and repair locations. As a result of installed smart grid relay equipment, there is a reduction on time spent locating failures reducing crew labor and associated costs.

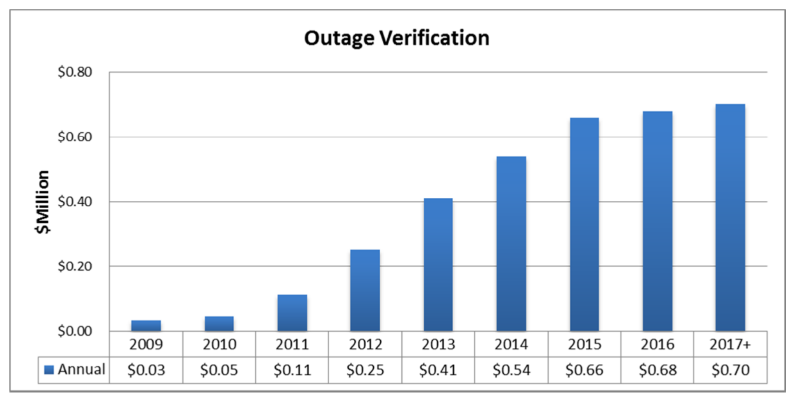
Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Number of Outages (reduction reflected in Benefit 12)
- Outage Duration (reduction reflected in Benefit 12)
- Hourly Labor Rate (varies by resource and storm type)
- Labor Inflation
- Non-labor Restoration Costs (out-of-area crews and travel)
- Number of Restoration Crew Members
  - 15% Crew Time Reduction for level 1 storms
  - 10% Crew Time Reduction for level 2,3,4 storms
  - 20% Crew Time Reduction for OCB/Reclosers

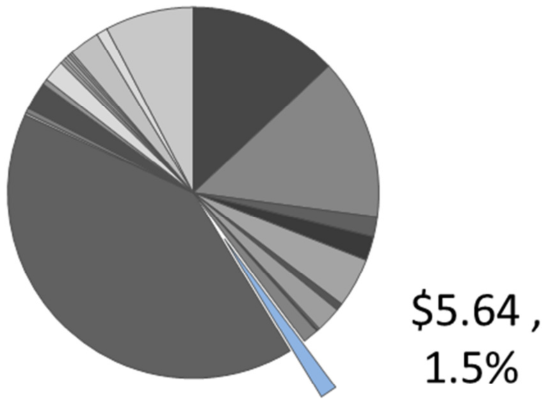
These values were just a consensus judgment from several Duke Energy SMEs with experience in storm and service restoration based on having more precise and immediately available data on which customers are still out of service and the ability to determine if any customers fed by a device are still out after Duke Energy thinks the outage caused by that device is restored.

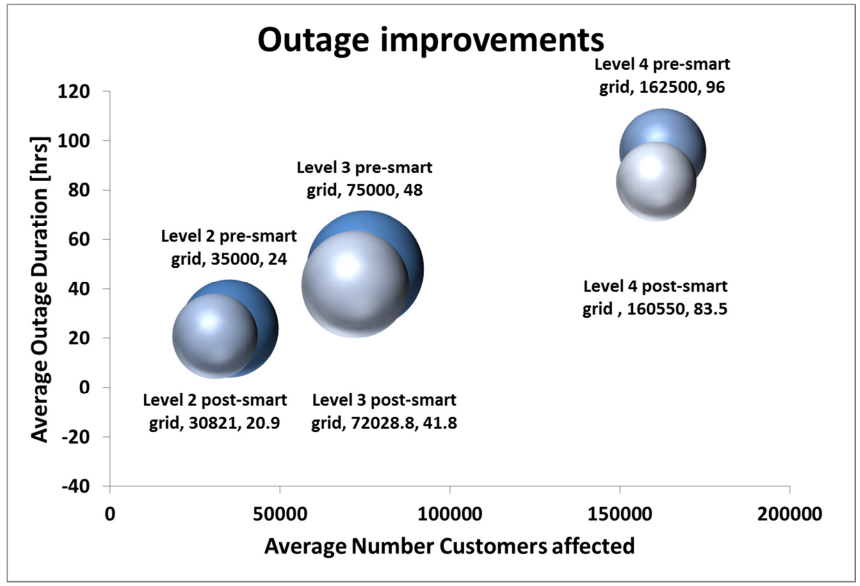
Modeled Economic Benefit



Outage Reductions – Revenue Impact (Benefit 12)

$ NPV in millions/% of total benefit





Savings Category – Increased Revenue

Background on Benefit

- The smart grid's outage restoration reporting functionality can be expected to reduce total time for service restoration, thus increasing Duke Energy Ohio's revenue associated with customers whose service has been severed during outage events.
- The smart grid's improved "sectionalization" capabilities help utilities isolate faults better and reduce the number of customers impacted by an outage. Self-healing teams are a more sophisticated means of accomplishing the same objective using a combination of circuit breakers, reclosers, self-healing team switches, sectionalizers, and fuses. In either case, Duke Energy Ohio's revenue increases when the average number of customers impacted by each outage decreases.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Number of Outages
- Outage Duration (hrs.)
- Average Number of Customers Affected
- % of Outage Spent in Assessment (Assessors)
- Reduction in Assessment Time (See benefit 10)
- Average Customer Hourly Power Consumption
- Reduction in Customers Affected Due to Self-Healing
  - 60% Reduction for level 2 storms
  - 20% Reduction for level 3 storms
  - 0% Reduction for level 4 storms
- Number of Circuits with Self-Healing Teams

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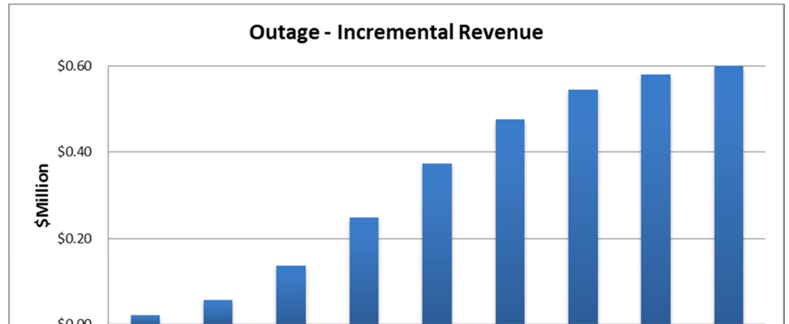
- Reduction in Customers Effected Due to Sectionalization
  - 25% Reduction for level 2 storms
  - 8% Reduction for level 3 storms
  - 4% Reduction for level 4 storms
- Number of circuits with Sectionalization

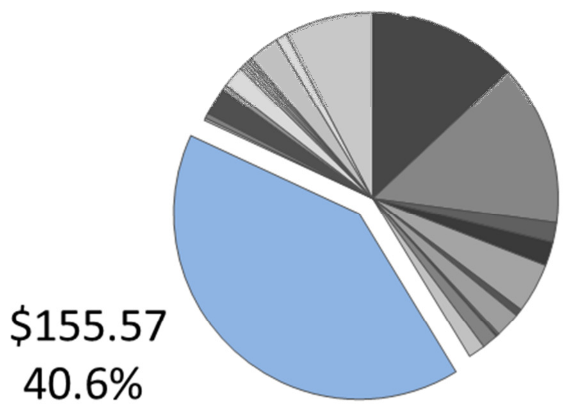
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.02	$0.06	$0.14	$0.25	$0.37	$0.48	$0.54	$0.58	$0.60

24/365 System Voltage Reduction Strategy (Benefit 13)

$ NPV in millions/% of total benefits



Savings Category – Avoided Fuel Cost

Background on Benefit

Smart grid “Voltage Reduction Strategy” is based on the same principle as a light dimmer. It’s intuitive that when a light dimmer is turned down, the energy usage is reduced. Energy reduction is the objective of Voltage Reduction Strategy. But to do this in a meaningful manner for a grid, several issues need to be addressed. For example and hypothetically speaking, if one dimmer was controlling all the lights in a city on one very long wire, the lights at the end of the wire would not be as bright as the closer ones. This issue is due to a phenomenon called “voltage drop”, and is fixed by activating “capacitor banks”, which have similar properties as batteries, along the length of the power line. These “batteries” supply just enough additional power to counteract the voltage drop so the lights at the end of the line are as bright as those closer to the dimmer.

An interesting thing happens if every other light on the long line were turned off; the voltage drop is reduced. So a smarter way to operate the dimmer and batteries would be to turn down the dimmer a little bit and deactivate the batteries when unnecessary while continuously monitoring that all the lit lights are still as bright as they are specified to be. Even if the dimmer is only turned down slightly, the total energy savings from all the lights combined is substantial.

“System Voltage Reduction” is often named Conservation Voltage Reduction (CVR) or Integrated Volt VAR Control (IVVC), and results in avoided fuel cost and some distribution capital deferment. IVVC is typically enabled by smart grid equipment such as Voltage Regulators/Load Tap Changers (very large dimmers), capacitor banks, and sophisticated software applications in the DMS.

An IVVC algorithm has two distinct but related functions:

- Reduce the voltage drops over the length of a feeder/circuit by activating capacitor banks
- Lower the voltage while maintaining a safety margin from minimum allowable levels

Algorithms in the DMS software alternates five minute periods of voltage flattening and voltage reduction and continually make control decisions based on real-time voltage readings from the capacitors, substation equipment, and line sensors on the feeder/circuit.

Load Tap Changers and capacitors play important roles in traditional grids as well, but their operation is not as automated or coordinated:

Step 1: Reduce voltage drop along the line.

Step 2: Lower the voltage-while maintaining a safety margin from minimum allowable levels).

Determining Energy Savings of a Hypothetical 2% Voltage Reduction

The amount of energy saved from a given level of voltage reduction is a matter of debate and varies from feeder to feeder based on several factors. In summary, some types of loads do not react to changes in voltage, while other types of loads “work harder” in response to voltage reductions.

As a result, there is not a one-for-one relationship between voltage reductions and energy reductions. Studies indicate energy savings from

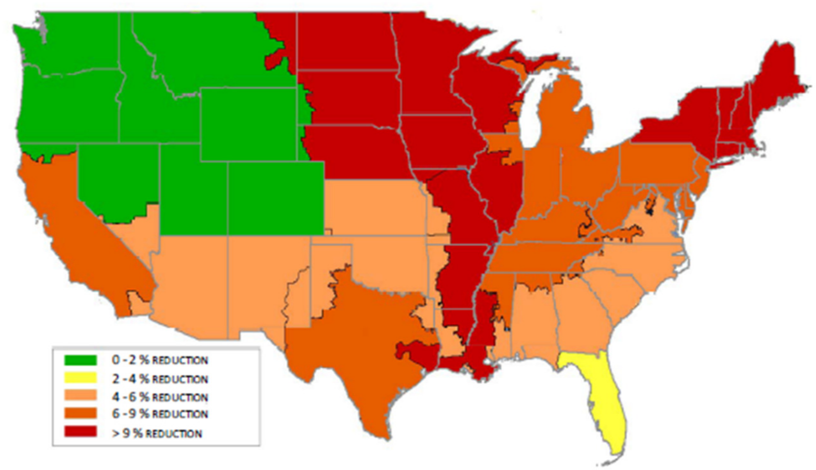
0.50% to 0.79% for a 1.0% drop in voltage, with common mode values of 0.65%. The ratio between energy savings and voltage reduction is becoming known as the CVR factor. MetaVu used these 3 values (0.50%, 0.65%, and 0.79%) in low case, base case, and high case estimates, respectively.

Impact of CO2-related EPA regulations on Operating Benefit Fuel Cost Assumptions

Assumptions on the cost of future EPA carbon regulation compliance are relevant to all Operational Benefits with a fuel cost component. The topic is addressed here because the impact is greater in this Operational Benefit than the others if future regulations are implemented.

- If the EPA is successful in implementing new CO2 emissions standards as currently outlined, NERC estimates that 6-9% of Ohio capacity will become economically obsolete. (Source: NERC Special Reliability Scenario Assessment, October 2010, page 13+.)
- Replacing a conservative estimate of 5% of Duke Energy's Generating Capacity with modern/up-to-CO2-standard power plants can be translated into a 4% one-time increase in fuel cost/LCOE. MetaVu has accounted for the one-time increase in the modeling under the assumption that EPA regulations will take effect in 2016.
- An energy efficiency savings modeling tool popular with many utilities, DSMore from Integrated Analytics, was used to model the value of fuel cost savings (including capacity value) from voltage reductions. Duke Energy provided proprietary system-wide hourly load profiles for the DSMore modeling.

Figure 5: 2018 Reduction in Adjusted Potential Capacity Resources due to the Combined EPA Regulation Scenario

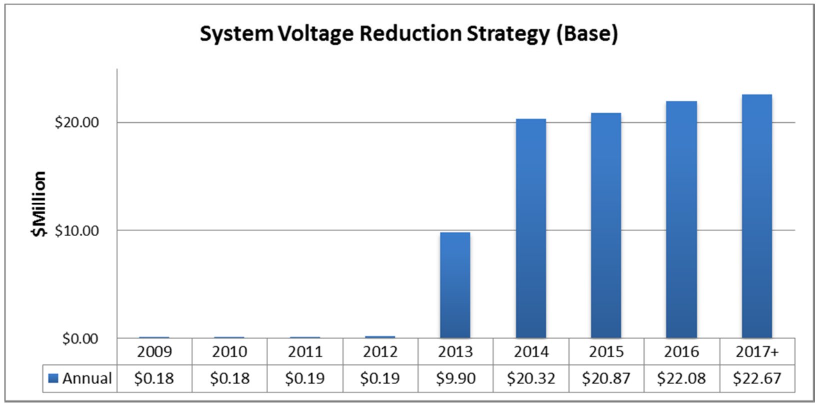


Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

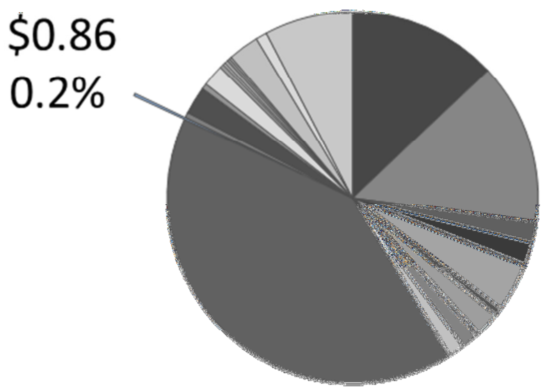
- Cost Avoided Production (Energy/Fuel)
- Cost Avoided Production (Capacity)
- CVR-Factor
- Purchased Power/Fuel Cost Escalation Single Year (2016)
- DMS Deployment Schedule

Modeled Economic Benefits



Power Shortage Voltage Reduction (Benefit 14)

$ NPV in millions/% of total benefits



Savings Category – Capital Deferment

Background on Benefit

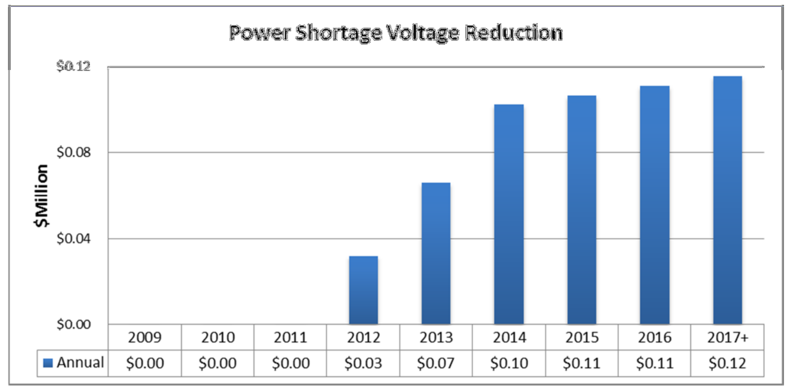
- Improved voltage control (i.e., stable distribution voltage profiles) enables voltage levels to be reduced in the distribution system for load reduction without impacting customer service, resulting in reduced capital investment as a result of mitigating peak loads and lower operating expenses during peak load conditions.
- An energy efficiency savings modeling tool popular with many utilities (DSMore from Integrated Analytics) was used to model the value of capacity avoided through voltage reductions. Duke Energy provided proprietary system-wide hourly load profiles for the DSMore modeling.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

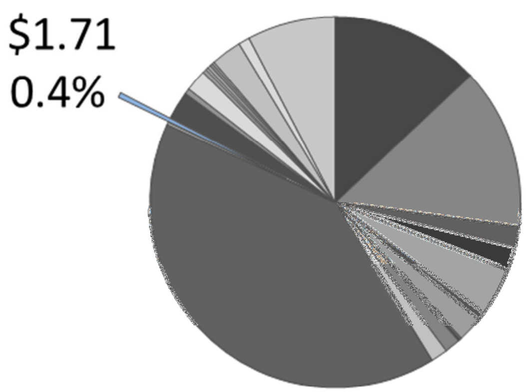
- Cost of avoided Capacity
- CVR Factor: 0.65%/1.0%

Modeled Economic Benefit



Continuous Voltage Monitoring (Benefit 15)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

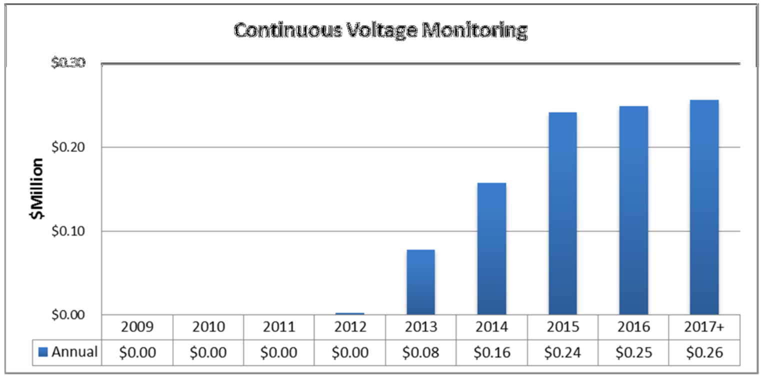
- Improved capability in automated monitoring of voltage for low voltage situations allows for a major reduction in the time field employees currently spend performing this function.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

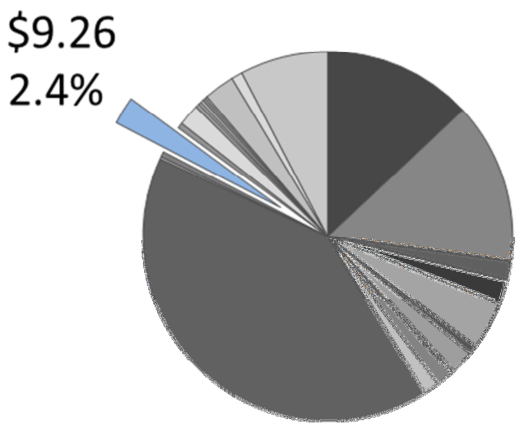
- Number of FTEs Checking Low Voltage Issues
- Cost per FTE
- Labor inflation rates
- Estimated Savings Percentage
- Meter Deployment Rate

Modeled Economic Benefit



VAR Management (Benefit 16)

$ NPV in millions/% of total benefits



Savings Category – Capital Deferment

Background on Benefit

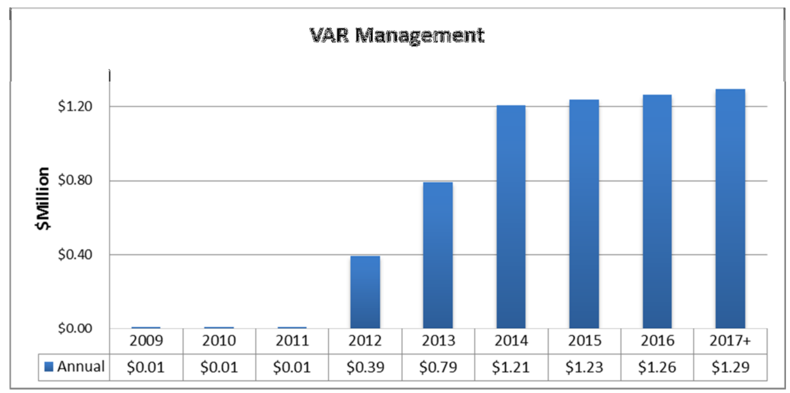
- Capacitors improve the power factor (VAR) of energy and increase the effective carrying capacity of existing plants and distribution equipment.
- Duke Energy's smart grid deployment plans include equipment that monitors and reports the status of capacitors. With this feature, faulty capacitors can be identified and repaired or replaced immediately.
- Prior to smart grid deployment, capacitors might be offline for a year before being detected. Rapid detection and repair improves capacitor effectiveness and enables the avoidance/deferral of capital expenditures.

Benefit Drivers

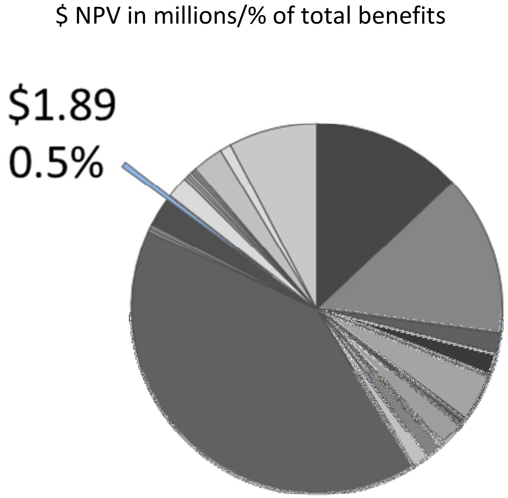
The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Distribution Peak Load
- VAR Improvement %
- Percent Capacitors Offline
- Carrying Cost of Plant
- DA Deployment Schedule

Modeled Economic Benefit



Asset Management (Benefit 17)



Savings Category – Capital Deferment

Background on Benefit

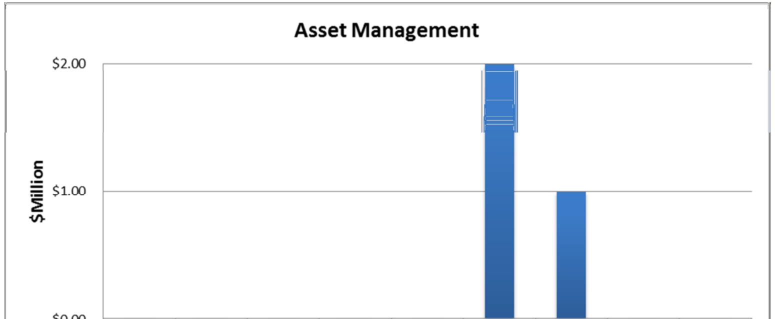
- Distribution equipment, including substations and feeders, must be upgraded from time to time to increase capacity as dictated by customer demand.
- Smart grid enhancements offer improved grid data access and analysis capabilities that can be used to switch loads from one feeder or substation to another.
- Optimized load switching can be used to relieve grid assets that are approaching capacity. It is possible to delay capacity upgrades one-two years by better distributing loads across available assets, deferring capital expenditures.
- Based on this, the resulting assumption is that two substation upgrades could be delayed per year, one substation by one year and the second substation by two years.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

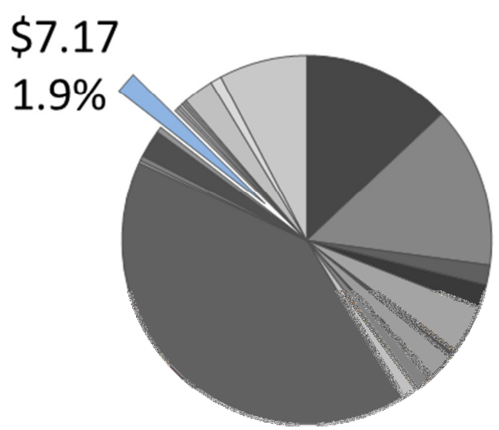
- Cost of one substation
- Load Growth
- Load Shifting/Reconfiguration opportunity

Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.00	$0.00	$0.00	$0.00	$2.00	$1.00	$0.00	$0.00

System Fine Tuning (Benefit 18)



Savings Category – Avoided Fuel Cost and Capital Deferment

Background on Benefit

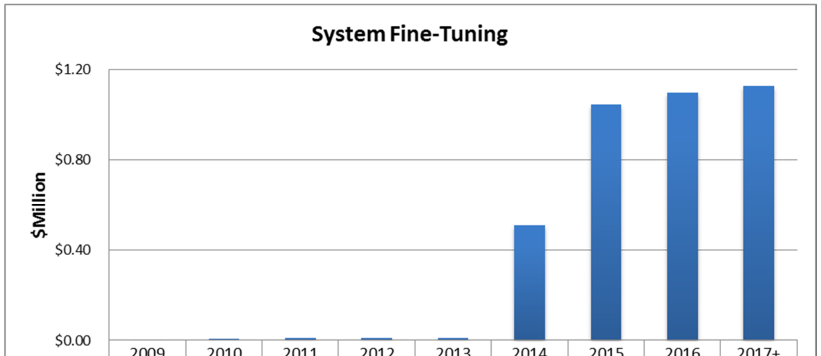
- Fine tuning enables more efficient distribution of power (e.g., reduced line losses in the medium voltage three phase portion of the distribution). This results in the need for less capital investment (in distribution, transmission, and generation assets) for handling peak load and improved overall operating expenses (i.e., less power needs to be generated or purchased to service the load) – on an ongoing, real-time basis.
- DMS software must be engaged to activate fine tuning and to enable this benefit.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Main Line Loss (% of Power)
- Reduction in Losses (% of losses)
- Annual Retail Sales
- Total Electric Loss (T&D)
- Cumulative Residential Energy Growth
- Weighted Average Fuel Cost (an average based on a mix of fuel types)
- Annual Fuel Cost Escalation
- Fuel Cost Escalation Single Year (2016)
- Carrying Cost of Plant

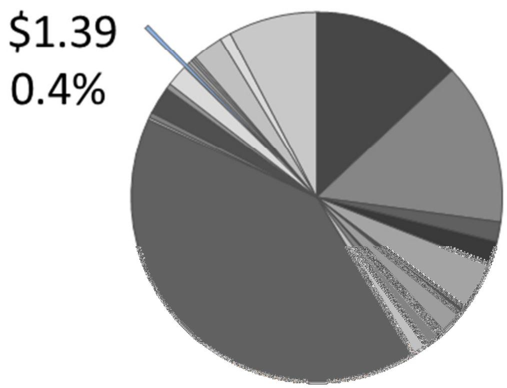
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.01	$0.01	$0.01	$0.01	$0.51	$1.04	$1.10	$1.13

Capacitor Inspection Costs (Benefit 19)

$ NPV in millions/% total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

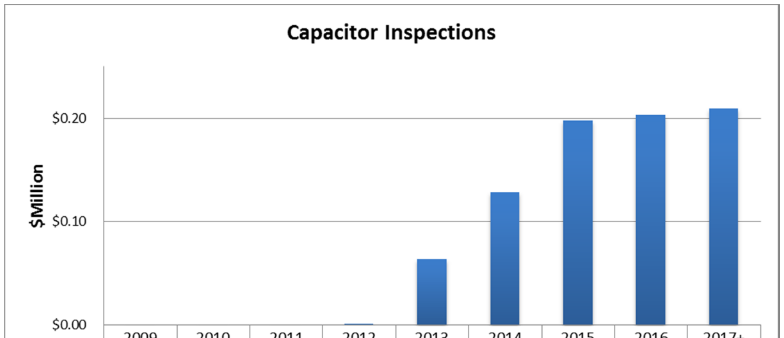
- New capacitor bank controllers and communication modems will be leveraged to produce alarms and exception reports when issues arise at each capacitor bank. These alarms will be near real-time, which will greatly reduce the need for onsite inspections.
- Prior to the smart grid, each capacitor bank was inspected annually. Going forward one fifth of the capacitor banks will be inspected annually. Therefore, smart grid technology reduces visual walk-by inspections by eighty percent with associated savings in labor and operations costs.
- For this benefit to take effect an approval for waiver of existing regulatory rules associated with applicable capacitor inspection frequency would be required.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Planned Reduction in Capacitor Bank Inspections
- Labor Inflation Rate
- Cumulative Cap Bank Controller & Modem Deployment
- Number of Capacitor Banks
- Cumulative Growth in Capacitor Banks
- Hourly Labor Rate
- Average Number of Hours per Capacitor Bank Inspection Including Field Work and Back-Office Logging and Reporting

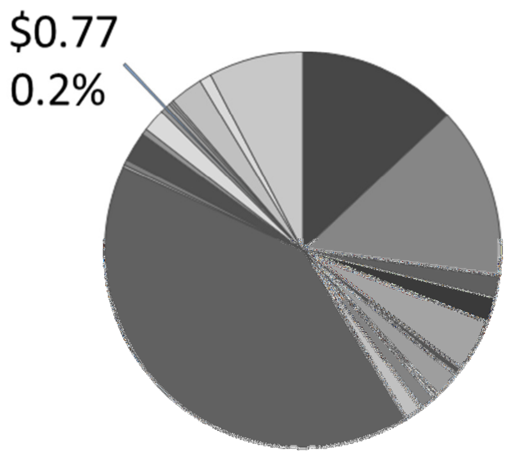
Modeled Economic Benefit



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.00	$0.00	$0.00	$0.06	$0.13	$0.20	$0.20	$0.21

Circuit Breaker Inspection Costs (Benefit 20)

$NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

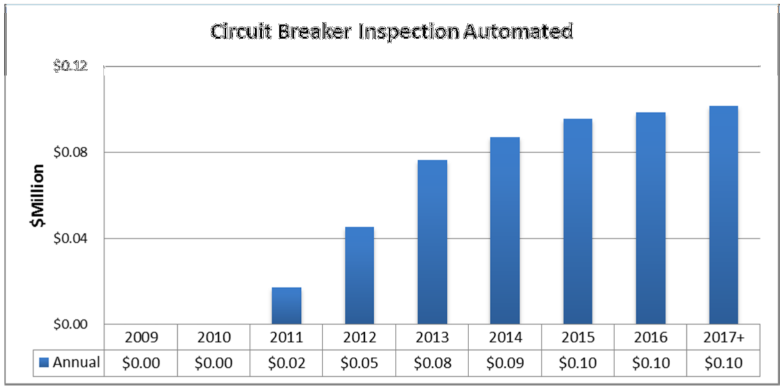
- Legacy reclosers inside substations without communication capability are being replaced by modern circuit breakers that are smart and integrated. Ultimately, the condition of the new circuit breakers will be available remotely in the new DMS and eliminate the need for circuit breaker inspections.
- During the first half of deployment, the circuit breaker data is being tagged in the existing Energy Management System (EMS) interface and stored in the data archive. Partial benefits could therefore be available in advance of DMS deployment.
- For this benefit to take effect an approval for waiver of existing regulatory rules associated with applicable circuit breaker inspection frequency would be required.

Benefit Drivers

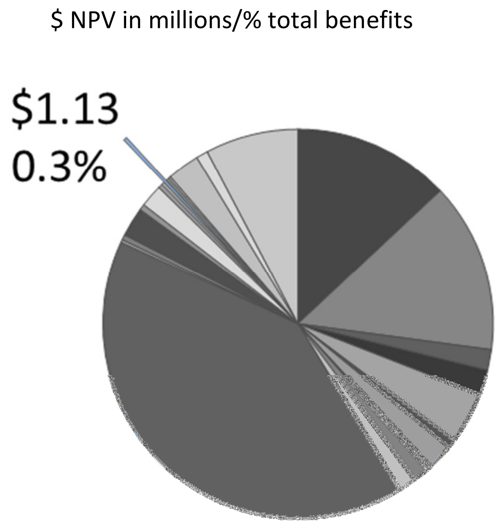
The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Projected Annual Labor Cost Savings
- Labor Inflation Rate
- Cumulative Hardware & Communications Deployment

Modeled Economic Benefit



Call Center Efficiency (Benefit 21)



Savings Category – Avoided O&M Cost

Background on Benefit

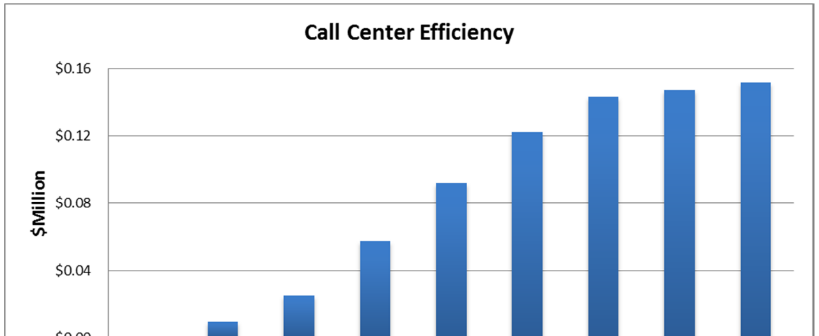
- With greater capabilities associated with AMI technology, such as remote meter reads, remote diagnostics, and more granular historical data, the number of customer calls is expected to decrease over time. Calls related to credit and billing issues, move orders, and trouble calls for both gas and electric are anticipated to be reduced.
- Traditionally, the utility had access to only monthly meter reads which provided call center employees little information to handle customer calls. With AMI technology, call center employees can use granular historical data to help resolve questions or complaints. In addition, reductions in estimated bills also reduce the number of customer calls. Remote diagnostic meter reads can assist in resolving trouble calls as mentioned in Benefit 3 and reduce the number of meter order calls that occur from rescheduling appointments for indoor or other hard-to-access meters.
- Customers with access to the Customer Portal will have the capability to view their detailed usage online. Customers with smart meters can access this data and resolve questions prior to calling the call center.

Benefit drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- The deployment rate of smart electric meters and gas modules
- Reduction in credit, billing, move order and trouble calls
- Labor inflation rates

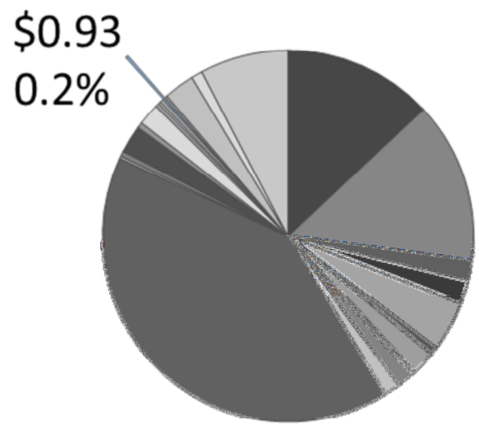
Modeled Economic Benefits



	2009	2010	2011	2012	2013	2014	2015	2016	2017+
Annual	$0.00	$0.01	$0.03	$0.06	$0.09	$0.12	$0.14	$0.15	$0.15

Increase in Safety (Benefit 22)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

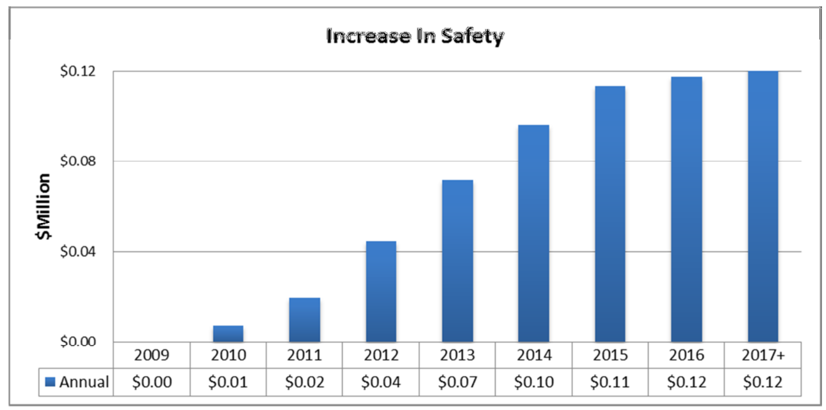
- As AMI technology reduces staff in the Meter Reading department, labor costs will drop. Worker's compensation costs, which are assessed based on labor costs, will drop as well.
- In addition, Duke Energy Ohio may experience reductions in workers' compensation insurance rates, though this impact is difficult to quantify. The reduction of maintenance/inspections on distribution equipment and remote operation of field devices, for example, will result in reduced exposure to field hazards and greater levels of safety for field crews and linemen. Over time, reduced frequency of safety incidents should result in lower worker's compensation insurance rates.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

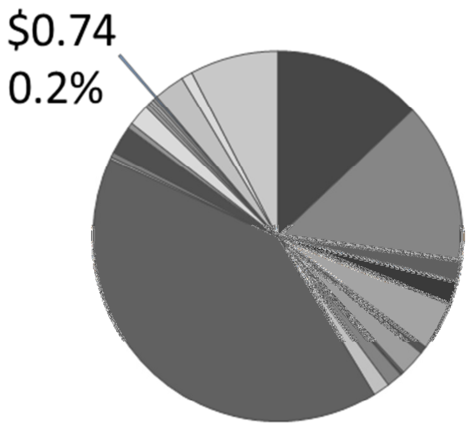
- The deployment rate of smart electric meters and gas modules
- Annual cost workman's compensation for Meter Reading
- Annual cost of vehicle accident claims
- Meter reader reduction resulting in meter reading route consolidation and meter reader staff reduction

Modeled Economic Benefits



Billing Savings – Shortened Billing Cycle (Benefit 23)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Costs

Background on Benefit

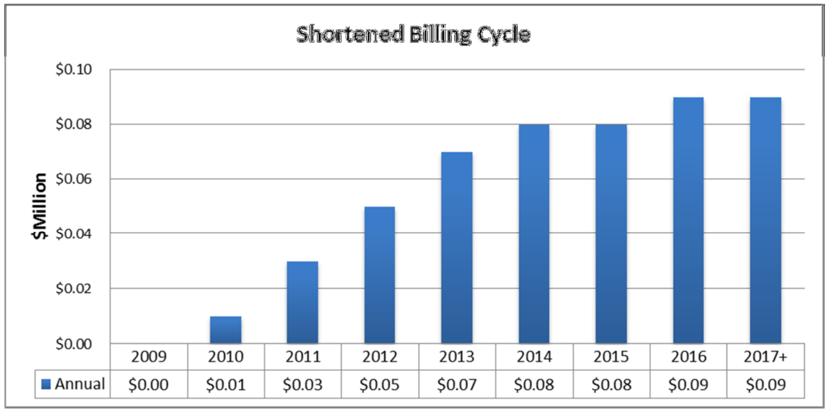
- Smart meters will almost always provide billing data on the scheduled read day, allowing the bills to be made available on the first day of the billing cycle.
- Traditionally, some bills are not issued on the first day of the billing cycle. Most of these are estimated, delaying billing by as much as 2 days.
- By reducing the number of bills issued on a delayed basis, cash collections will be accelerated and interest expense can be reduced.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

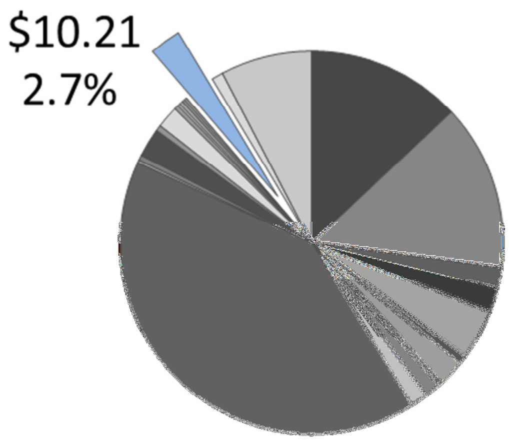
- The deployment rate of smart electric meters and gas modules
- Duke Energy's discount rate
- Electric and gas load growth rates
- Electric and gas price inflation
- The number of estimated bills

Modeled Economic Benefits



Vehicle Management Costs (Benefit 24)

$ NPV in millions/% of total benefits



Savings Category – Avoided O&M Cost

Background on Benefit

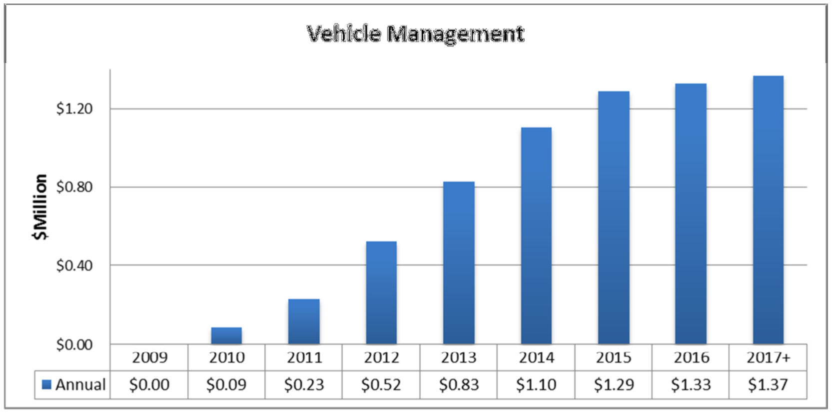
- Smart meters will result in the reduction of vehicles used for meter reading.
- Duke Energy in Ohio has traditionally employed Meter Readers to manually read meters on a monthly basis. This process consists of individuals capturing electric and gas meter data in the field. Meter Readers then provide meter data to the utility for billing purposes.
- With the deployment of smart meters, metering data is communicated via a wireless network to the utility. This reduces the need for most manual meter reads, meter readers, and meter reading vehicles.
- It should be noted, despite a significant decrease in vehicles used for meter reading, the average miles driven per remaining meter reader will increase. Traditionally, Meter Readers walked door-to-door routes. With AMI technology, very few meters will need manual meter reads, and distance between manual meter read locations will be much further.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

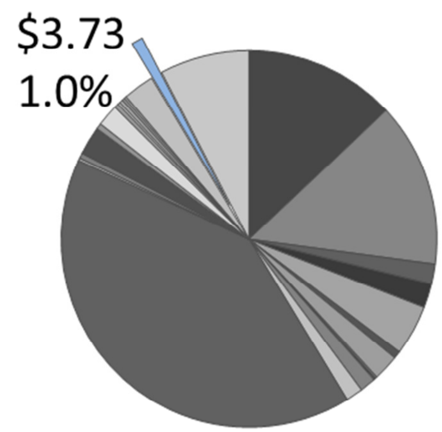
- The deployment rate of smart electric meters and gas modules
- Cost of insurance premium per vehicle
- Total meter reading vehicles
- Average miles driven per year
- Inflation rate of materials

Modeled Economic Benefits



Fuel Cost Reduction through VAR Improvement (Benefit 25)

$ NPV in millions/% of total benefits



Savings Category – Avoided Fuel Cost

Background on Benefit

- Improved Power Factor (VAR) performance from DMS-enabled IVVC and VAR management will reduce line losses, resulting in fuel cost reductions.

Line loss improvements due to VAR improvements were not captured in the other benefits that relate to IVVC and VAR management (13 and 18)

Benefit Drivers

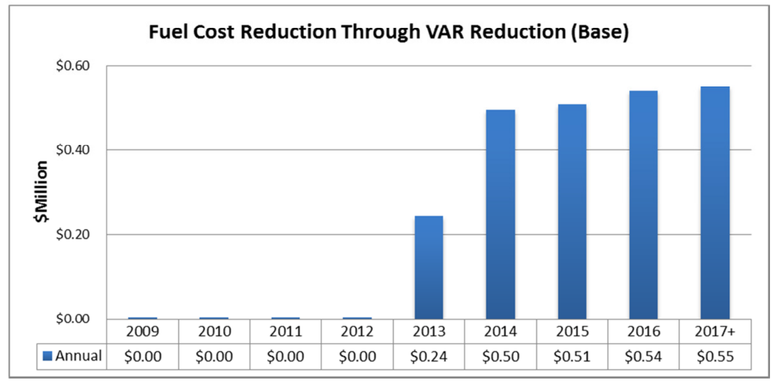
The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Percent of Feeders with relatively poor VAR performance
- Amount of line loss improvement available from VAR improvement
- Amount of line losses as a result of poor VAR

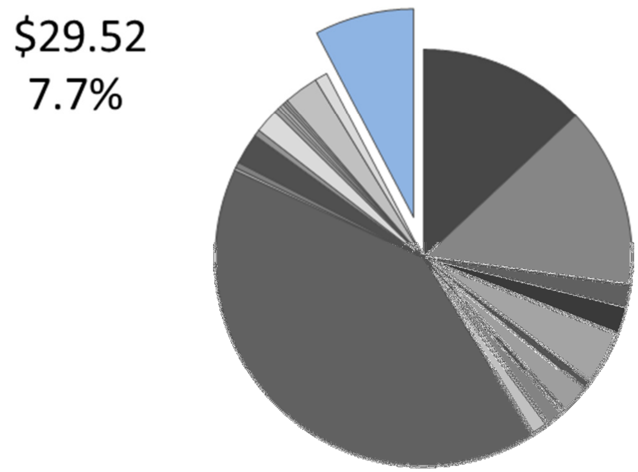
Assumptions:

	Low Case	Base Case	High Case
Poor-performing Feeders	25%	50%	75%
PF improvement	From .85 to .99	From .96 to .985	From .96 to .985
Line Loss	1%	3%	5%

Modeled Economic Benefit



Wholesale Energy Sale of Capacity Made Available (Benefit 26)



Savings Category – Increased Revenue

Background on Benefit

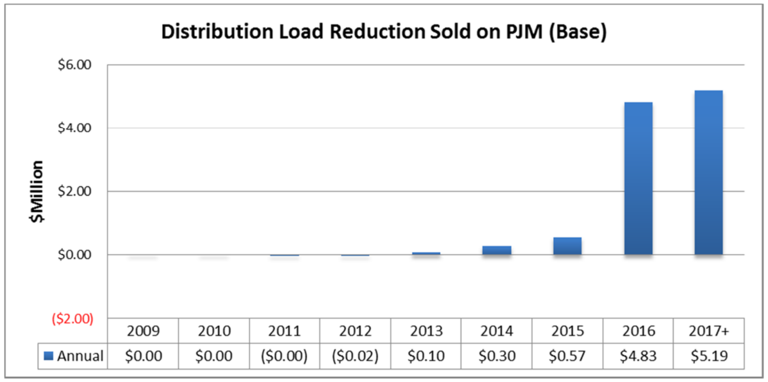
- Freed up capacity from smart grid-related distribution load reductions in Ohio may be used to produce energy that can be sold into the wholesale market (PJM). Historical PJM Locational Marginal Prices (LMP) shows that there are opportunities for profitable sales when market prices exceed the Cost of Energy (COE).
- The ability of Duke to sell into the wholesale market depends on whether they are long or short on generation to serve Standard Service Offer (SSO) load ("native" or "non-shopping" load).
- Whether Duke is long or short depends on shopping levels.
- Sales volumes are anticipated to fall as a result of smart grid deployment, all else being equal. Lost margins associated with this reduction have been netted against this benefit.

Benefit Drivers

The characteristics and assumptions that most significantly impact the calculation of this economic benefit include:

- Annual Energy Saved from Benefit 13, System Voltage Reduction 24/365
- Annual Energy Saved from Benefit 18, System Fine Tuning
- Annual Energy saved from Benefit 25, VAR Improvement
- Energy Used Benefit 12, Incremental Revenue from Reduced Outage time
- Low Case: Assume cost at $61.10; Wtd Ave LMP $81.98
- Mid Case: Assume cost at $47.10; Wtd Ave LMP $63.15
- High Case: Assume cost at $28.10; Wtd Ave LMP $47.41
- Percentage of Time when price is above cost
  - Low: 13.8% (1,213 hours)
  - Mid: 35.7% (3,124 hours)
  - High: 87.3% (7,649 hours)
- Fuel Cost Escalator
- Weighted Average Fuel Cost
- Transmission Losses to PJM/MISO
- Duke Ohio Total Retail Sales 2010
- Effective Date of Next Rate Case (Jan. 1st 2016)
- Lost Margins Estimate ($12.30/MWh T&D Margin per Case No. 09-1999-EL-POR, Jim Ziolkowski testimony Attachment 1, Feb. 15, 2011.)

Modeled Economic Benefit



Operational Benefits Summary table ($ millions)

Assessment ID	20-Year NPV	Year 1 NPV	Year 2 NPV	Year 3 NPV	Year 4 NPV	Year 5 NPV	5-Year NPV	Year 6 NPV	Year 7 NPV	Year 8 NPV
		2009	2010	2011	2012	2013	Total	2014	2015	2016
1(b) Base	$ 49.86	$ -	$ 0.31	$ 0.43	$ 0.98	$ 2.03	$ 3.75	$ 2.93	$ 3.61	$ 3.90
2(b) Base	$ 53.96	$ -	$ 0.72	$ 1.54	$ 2.55	$ 3.52	$ 8.33	$ 3.96	$ 4.18	$ 4.03
3(b) Base	$ 6.53	$ -	$ 0.05	$ 0.11	$ 0.23	$ 0.35	$ 0.74	$ 0.44	$ 0.48	$ 0.46
4(b) Base	$ 7.94	$ -	$ 0.06	$ 0.15	$ 0.28	$ 0.43	$ 0.92	$ 0.52	$ 0.60	$ 0.57
6(b) Base	$ 16.58	$ -	$ 0.12	$ 0.30	$ 0.68	$ 0.93	$ 2.03	$ -	$ -	$ -
7(b) Base	$ 2.43	$ -	$ 0.02	$ 0.04	$ 0.09	$ 0.14	$ 0.29	$ 0.17	$ 0.18	$ 0.18
8(b) Base	$ 8.51	$ -	$ 0.07	$ 0.16	$ 0.30	$ 0.46	$ 0.98	$ 0.56	$ 0.64	$ 0.61
9(b) Base	$ 0.66	$ 0.05	$ 0.01	$ 0.08	$ 0.16	$ 0.15	$ 0.45	$ 0.11	$ 0.10	$ -
10(b) Base	$ 0.59	$ 0.00	$ 0.00	$ 0.01	$ 0.02	$ 0.03	$ 0.07	$ 0.04	$ 0.04	$ 0.04
11(b) Base	$ 5.22	$ 0.03	$ 0.04	$ 0.09	$ 0.19	$ 0.28	$ 0.64	$ 0.35	$ 0.40	$ 0.38
12(b) Base	$ 5.64	$ 0.02	$ 0.05	$ 0.11	$ 0.19	$ 0.26	$ 0.62	$ 0.31	$ 0.33	$ 0.32
13(b) Base	$ 155.57	$ 0.17	$ 0.16	$ 0.15	$ 0.14	$ 6.86	$ 7.48	$ 13.10	$ 12.50	$ 12.29
14(b) Base	$ 0.86	$ -	$ -	$ -	$ 0.02	$ 0.05	$ 0.07	$ 0.07	$ 0.06	$ 0.06
15(b) Base	$ 1.71	$ -	$ -	$ -	$ 0.00	$ 0.05	$ 0.06	$ 0.10	$ 0.14	$ 0.14
16(b) Base	$ 9.26	$ 0.01	$ 0.01	$ 0.01	$ 0.29	$ 0.55	$ 0.87	$ 0.78	$ 0.74	$ 0.70
17(b) Base	$ 1.89	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.29	$ 0.60	$ -
18(b) Base	$ 7.17	$ -	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.03	$ 0.33	$ 0.62	$ 0.61
19(b) Base	$ 1.39	$ -	$ -	$ -	$ 0.00	$ 0.04	$ 0.05	$ 0.08	$ 0.12	$ 0.11
20(b) Base	$ 0.77	$ -	$ -	$ 0.01	$ 0.03	$ 0.05	$ 0.10	$ 0.06	$ 0.06	$ 0.05
21(b) Base	$ 1.13	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.06	$ 0.14	$ 0.08	$ 0.09	$ 0.08
22(b) Base	$ 0.93	$ -	$ 0.01	$ 0.02	$ 0.03	$ 0.05	$ 0.10	$ 0.06	$ 0.07	$ 0.07
23(b) Base	$ 0.74	$ -	$ 0.01	$ 0.02	$ 0.04	$ 0.05	$ 0.12	$ 0.05	$ 0.05	$ 0.05
24(b) Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25(b) Base	$ 10.21	$ -	$ 0.08	$ 0.18	$ 0.39	$ 0.57	$ 1.22	$ 0.71	$ 0.77	$ 0.74
26 Base	$ 3.73	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.17	$ 0.18	$ 0.32	$ 0.30	$ 0.30

6 APPENDICES

1. Meter Test Plans
2. Field Audit Results
3. Guidelines and Practices Detail
4. TOU Billing Data
5. Smart Meter Data Audit
6. References
7. Inputs and Assumptions
8. Meter Accuracy Weighting
9. Glossary
10. Project Partner Qualifications

7 APPENDIX 1: METER TEST INSPECTION

Meter Testing

Testing of meters was carried out by Alliance Calibration, an accredited test laboratory in the Greater Cincinnati Area, in accordance with a subset of the meter type testing standards, ANSI C12.20. Sample selection of meters undergoing test (MUT), the testing and the test results are documented in a test report which was then reviewed by MetaVu and prepared for the smart grid report by Alliance Calibration.

MetaVu has assessed that the tests have been carried out in accordance with the appropriate test procedures and that they properly document the aspects required for this evaluation.

Load Measurements

Electric load measurements were required for accuracy evaluation. The tests were conducted according to the minimum requirements given below. The purpose of "Load Testing" was to provide data to enable MetaVu to estimate accuracy. For Load Testing, the specific load and consumption registration listed in ANSI C12.20 were measured.

Test Results Attestation

MetaVu attests that the necessary tests have been carried out by Alliance Calibration in accordance with relevant international standards.

Bench-testing was conducted by the staff of Alliance Calibration at the Alliance Calibration testing facility. The test engineer prepared a test plan which was inspected by the MetaVu staff and is additionally agreed to by both MetaVu and Alliance Calibration. This test plan conforms to the industry standard requirements including the descriptions for quality assurance of the testing process. The tests were conducted according to the test plan as attested to by the MetaVu staff. This attestation is, at a minimum, based on high level inspections of the following:

- All instrument calibrations required in the procedures described in the test plan
- All instrument model and serial numbers relevant to calibrations
- Representative Smart Meters under test
- Instrument electrical connections
- The quality of at least 48 passed lot MUTs test data

Test Reports

Test reports prepared by Alliance Calibration conform to the relevant standard used to define the test requirements. Each test report includes, at a minimum:

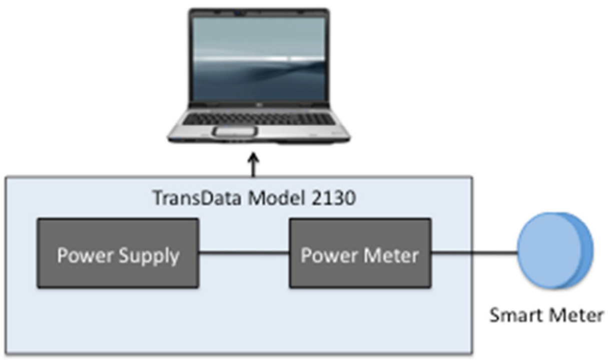
- A description of the MUT samples
- Lot including the serial number, and differences between the lot and the in-service meters
- A description of the test site
- Instrumentation
- Test procedure
- Test conditions
- Data analysis procedure

- Uncertainty analysis
- Results

7.1 Appendix 1-A: Electric Meter Test Plan

TransData Meter Testing Procedure

Simplified Test Layout



Meters were tested in our Laboratory and in an environmentally controlled chamber.

- All meters were tested as follows:
  - 240 Volts
  - 30 Amps
  - 3 Amps
  - Unity Power Factor
  - 50% Power Factor
- The Alliance Calibration Laboratory is maintained at 23^{o}C ±5^{o}and 20-30% Relative Humidity.
- The TransData 2130 Serial # 10502638 and Serial# 110504888 allows for the testing of various types of meters (electromechanical, digital and smart meters) and contains an internal Standard with an accuracy of +-0.025%.
- Proof of calibration traceable to NIST provided by Manufacturer.
- Refer to TransData technical specifications for specific details.
- A bar code scanner was used to read the unique meter identifier and this number is used as the identifier for test results.
- It is identified on the actual test report.
- The Test report also shows:
  - The Date the test was performed
  - The Technician who performed the test
  - The Test Constant
  - The Instrument Transformer Constant
  - The Meter Form
  - The Test setup name
  - The measured Quantity
  - The test report is generated as a PDF document that contains a time and date stamp.

Environmental Chamber Testing Conditions

- All meters were tested at -40^{o}C±0.5^{o} and + 40^{o}C±0.5^{o}.
- All meters were allowed to acclimate to temperature in the chamber for at least 24 hours before testing.
- The meter base was placed inside the chamber and TransData tester placed outside the chamber for all testing.
- These temperature ranges were selected as they represent the extreme range of temperatures on record from −25 to 109 °F (-32 to 43 °C) on January 18, 1977 and July 21, 1934, respectively by the National Weather Service.

Alliance Calibration	**Revision 1.0**
Procedure: P-114A	**Revision Date: 03/14/2011**
Title: 2S Watt Meters	

1.0 Purpose

1.1 The purpose of this document is to establish and maintain the procedure for calibration of 2S Watt Hour Meters

2.0 Scope

2.1 This procedure covers calibrations performed on all 2S Watt Hour Meters owned by Alliance Calibration or a customer contracting the services of Alliance Calibration

3.0 Authorization

3.1 Alliance Calibration Quality Manual

4.0 References

4.1 ISO 17025:2005

4.2 Manufacturer's specifications

4.2.1 Tolerance

4.2.2 Range

4.2.3 Limitations

5.0 Reference Standards and Equipment Used

5.1 Watt Hour Calibration Standard (TransData Model 2130 and computer with TransData software or equivalent)

5.2 2S Meter Socket

5.3 Associated wire leads as needed

Note: Before proceeding with the calibration the technician(s) must be familiar with the operation of the UUT, reference standards, and other equipment used in the calibration. In addition, safety considerations need to be taken into account to protect the UUT, reference standards, equipment, laboratory or the technician(s) from harm.

6.0 Detailed Procedure

6.1 Disconnect unit under test (UUT) from any external power source.

6.2 Disconnect voltage link located on rear of UUT.

6.3 Use an ohm meter to determine the correct terminal and connect opened voltage link to standard V-. Install meter into 2S meter socket.

6.4 Connect calibration standard to 2S meter socket as seen in attached diagram.

6.5 Affix optical pick up to meter. Use disk sensor for electromechanical meters of the Infra-red sensor for solid state meters.

6.6 Open the TransData software select "meter test" and then select the appropriate calibration program from the calibration computer software and ensure Kwh values match the value printed on the meter face.

6.7 When using the electromechanical disk sensor pick up apply full voltage and amperage and adjust the pick-up position and or sensitivity as required.

6.8 Fill in the meter identification number, the customer, and any additional information required in the software fields.

6.9 Click the "Begin As Found Test" button. The computer will control the testing of the meter. The meter will be tested on phase A and C for high current (30A @ unity power factor) power factor (30 @ 0.5 power factor) and light load (10% of full load test @ unity power factor). Phases A & C are tested separately to ensure any calibration deficiencies that may go unnoticed during series testing would be identified. Phase B is used only when calibrating 3-phase watt hour meters. The software will use the data from the optical pick up to calculate the value reported by the UUT and compare it to the calibration standard as a percentage value.

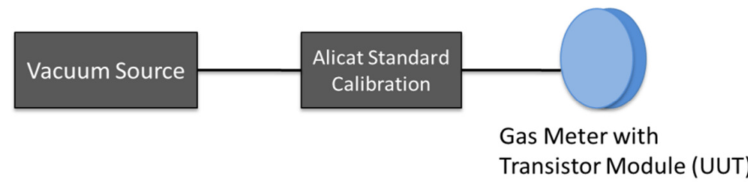
6.10 When calibration is complete the TransData standard will emit a series of beeps signaling the completion of testing for the UUT. Use the print button to generate a report of the calibration results.

6.11 Create certificate.

7.2 Appendix 1-B: Gas Meter Test Plan

Badger Transmitter Testing:

- Badger Transmitter connected to Gas Meter
- Known flow was applied at 23°C ±5°C at 20-30% relative humidity
- Readings were taken with a Trimble Ranger handheld meter reader Firmware5.0.3 serial #ss75c29567 and compared to known flow.



Alliance Calibration	**Revision 1.00**
Procedure: P-104A	**Revision Date: 5/2/2011**
Title: Calibration of Gas Flow Totalizers	
1.0 Purpose 1.1 The purpose of this document is to establish and maintain the procedure for the calibration of gas flow totalizing meters. Gas flow totalizing meters are intended to measure the amount of a gas that has been used over the course of time.	
2.0 Scope 2.1 This procedure covers calibrations performed on all gas flow totalizing meters owned by Alliance Calibration or a customer contracting the services of Alliance Calibration	
3.0 Authorization 3.1 Alliance Calibration Quality Manual	
4.0 References 4.1 ISO 17025:2005 4.2 Manufacturer's specifications 4.2.1 Tolerance 4.2.2 Range 4.2.3 Limitations 4.2.4 General operation of unit under test (UUT) 4.2.5 Safety considerations 4.3 Customer specifications 4.3.1 Tolerance 4.3.2 Range 4.3.3 Limitations	

5.0 Reference Standards and Equipment Used

5.1 Electronic mass flow meter with a totalize function of appropriate range for the unit under test (UUT) to be calibrated. (Typically Alicat Flow model PCU)

5.2 Tubing, hose, and fittings required to make necessary connections

5.3 Vacuum source

Note: Before proceeding with the calibration the technician(s) must be familiar with the operation of the UUT, reference standards, and other equipment used in the calibration. In addition, safety considerations need to be taken into account to protect the UUT, reference standards, equipment, laboratory or the technician(s) from harm.

6.0 Detailed Procedure

6.1 Connect the outlet of the UUT to the calibration standard inlet port.

6.2 Ensure the UUT inlet is free from obstructions.

6.3 Connect the outlet of the calibration standard to regulated vacuum source.

6.4 Turn on the calibration standard, and enter the device's totalize function.

6.5 Turn on the vacuum source and adjust the flow rate to be stable and representative of the UUT normal operating conditions.

6.6 Turn off the vacuum source and use the tare function of the calibrator and UUT. If the UUT does not have a tare function record the numerical readings prior to testing.

6.7 Turn on the vacuum source. Allow air to flow until a representative reading can be obtained.

6.8 Turn off vacuum source, record and compare readings. In the case of devices that do not have a tare function subtract the reading obtained in step 6.5 from the final reading to achieve the corrected reading for the UUT.

6.9 Repeat steps 6.1-6.7 for additional calibration points as required.

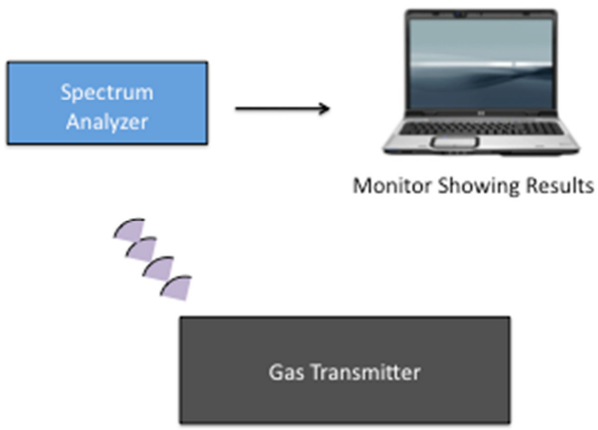
6.10 Create Calibration certificate.

Alicat Portable Calibration Unit:

- Serial # 60216-60217-60218
- See Alicat Portable Calibration Manual for Specifications

7.3 Appendix 1-C: Gas Transmitter Chamber Test Plan

Simplified Test Layout



Technical

The Federal Communications Commission (FCC) requires that all digital devices (including information Technology, Industrial, Scientific, and Medical Equipment) that operate with internal clock rates over 9 kHz be tested under one of more of the sections outlined in CFR Title 47, Parts 15, 18, 68, and 90.

Declaration of Conformity

In May 1996, the FCC allowed manufacturers of personal computer and peripherals to issue Declarations of Conformity (DoC's) in order to proclaim compliance of their products to Part 15. This was introduced as a way for manufacturers to get their products to market faster. Once the test report has been issues by an accredited test laboratory, the manufacturer can sell products immediately.

Certification

Some products, such as transmitters, are required to be certified by the FCC. Certification requires that an application be made to the FCC. The product may not be sold/marketed until the approval process is completed and the Certification is granted by the FCC.

Verification

Verification is a self-approval process. The equipment must be tested and the manufacturer must then maintain the test report and submit it to the FCC upon request. This process is typically used for Class A products such as business computers, TV and FM receivers, and Industrial, Scientific, and Medical Equipment.

Radio Frequency Overview

- FCC Registration Number (FRN): 0002723575
- Filing the FCC states device as low power transmitter
- 3rd party test firm recorded in filing
- Filing states frequency of 916.45 MHz

Radiated Emissions

The Badger Transmitter was initially placed in a semi-Anechoic RF Chamber, and wide band characterization measurements were performed to determine the frequencies at which significant emissions occurred.

The Badger Transmitter was tested at a distance of 3.0 meters. The emissions were maximized by rotating the table and raising/lowering the antenna mounted on a 4.0 meter mast. Cable and peripheral positions were also varied to produce maximum emissions. Both horizontal and vertical field components were measured. The output of the antenna was connected to the input of the receiver and emissions were measured in the range of 30MHz to 1GHz. The values up to 1GHz with a resolution bandwidth of 120 kHz are quasi-peak reading made at 3.0 meters. The raw measurements were corrected to allow for antenna factor and cable loss.

Conducted Emissions

The Badger Transmitter was placed on a 1.0 x 1.5 meter non-conductive table, 0.8 meter above a horizontal ground plane and 0.4 meter from a vertical ground plane. Power was provided to the EUT through a LISN bonded to a 3 x 2 meter ground plane. The LISN and peripherals were supplied power through a filtered AC power source. The output of the LISN was connected to the input of the receiver via a transient limiter, and emissions in the range 150 kHz to 30 MHz were measured. The measurements were recorded using the quasi-peak and average detectors as directed by the standard, and the resolution bandwidth during testing was 9kHz. The raw measurements were corrected to allow for attenuation from the LISN, transient limiter and cables.

Radiated Emission Testing

The EUT was positioned on an 80cm non-metallic table and tested on an Open Area Test Site, (OATS) at a distance of 3.0 meters. The emissions were maximized by rotating the table 360 degrees and raising/lowering the antenna mounted on a 4.0 meter mast. Cable and peripheral positions were also varied to produce maximum emissions. Both horizontal and vertical field components were measured. The output of the antenna was connected to the input of the receiver and emissions were measured in the range 30MHz to 1GHz. The values up to 1GHz with a resolution bandwidth of 120 kHz are quasi-peak readings made at 3.0 meters. The measurements above 1GHz with a resolution bandwidth of 1MHz are peak readings at a distance of 3.0 meters. The raw measurements were corrected to allow for antenna factor and cable loss.

Calculation of Data-Radiated Emission

The antenna factors of the antennas used, and the cable losses are added to the field strength reading recorded from the measurement receiver. The resultant field strength can then be compared to the FCC limits in dBµV/m. The following equation is used to convert to µV/m:

EµV/m = antilog (EdBµV/m /20)

Sample of Field Strength Calculation:

Ea =Va + AF + Ae

Where: Ea = Field Strength (dBµV/m)

Va= 20 x log10 (Measure RF voltage, µV)

Ae= Cable Loss Factor, dB

AF= Antenna Factor dB (m-1)

8 APPENDIX 2: FIELD AUDIT

8.1 Methodology

MetaVu randomly selected various pieces of Distribution Automation Equipment deployed by 2010 for the Audit. Selections were based on a list of deployed equipment that was provided in Duke's response to Data Request 39. Within a week, Duke had mapped out the selections on a GPS device, provided one-line diagrams and assigned a Duke employee to guide Alliance Calibration to the physical locations. The Physical Field Audit took place between February 22nd 2011 and April 6th 2011.

Checklist

The following information was captured for each piece of equipment:

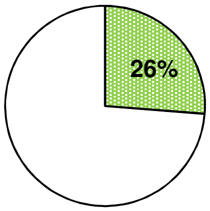
- Audit Date
- Unique identifier and circuit number labeled on equipment and used as tag in EMS(D-SCADA/DMS)
- Picture of Equipment/Enclosures/Unique Identifier
- For a subset of applicable equipment:
  - A time-stamped display reading or a switch position indication
  - A real-time call to the EMS operator checking that the EMS control center was reading the same on-screen
  - In follow-up at a later date Duke provided archived data for MetaVu to check system integration end-to-end

8.2 Result/Conclusion

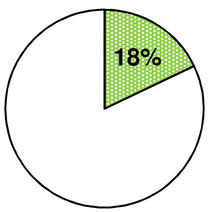
- All the Equipment selected for Audit was found to be installed. *(See Figures A2.1 and A2.2 below)*
- All display readings and switch position indicators matched up with EMS in real-time. *(See Figure A2.3 below).*
- All but one (Team 6 Montgomery Circuit 45 ID #29903) switch position matched the PI data. *(See Figure A2.4 below).* It is reasonable to conclude that the one that did not match is attributed to "noise" in the measurement because everything matched up in real-time. The cause of this is most likely a human error and can be attributed to one or more of the following:
  - The time stamp as captured was inaccurate
  - The switch position was written down incorrectly
  - The switch was operated within a minute of the physical audit (time stamps are rounded to nearest minute)
  - Duke operator may accidently have given inaccurate switch position from archived data

8.3 Outside the Fence Audit Selections

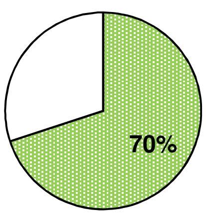
Electronic Reclosers audited=21 of 80



Sectionalization audited=36 of 201

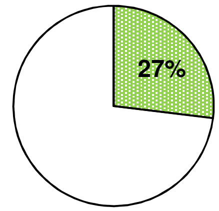


Self-Healing teams audited=7 of 10

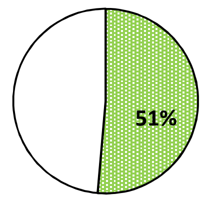


8.4 Inside the Fence Audit Selections

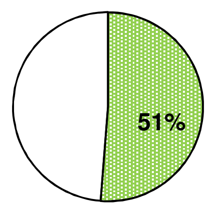
Circuit Breakers audited=7 of 26



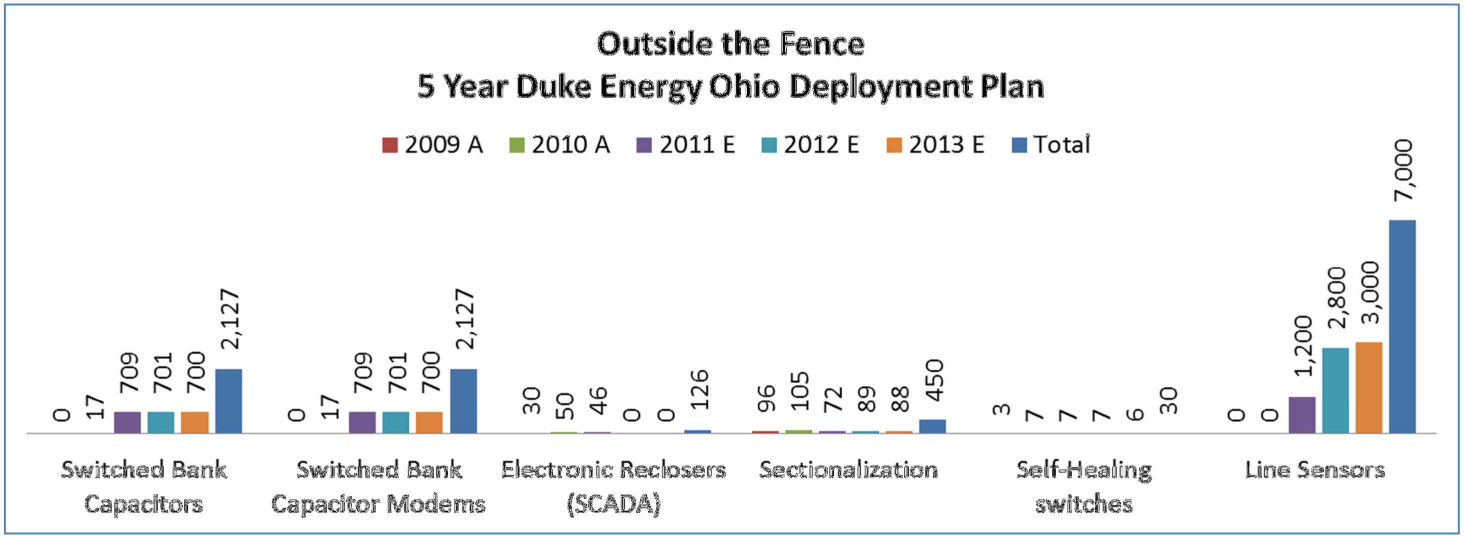
Relays audited=74 of 144



Substation Regulators audited=62 of 121



Figures A2.1 and A2.2 Field Audit Findings Actual deployment numbers for 2009 and 2010 - Estimates for 2011-2013



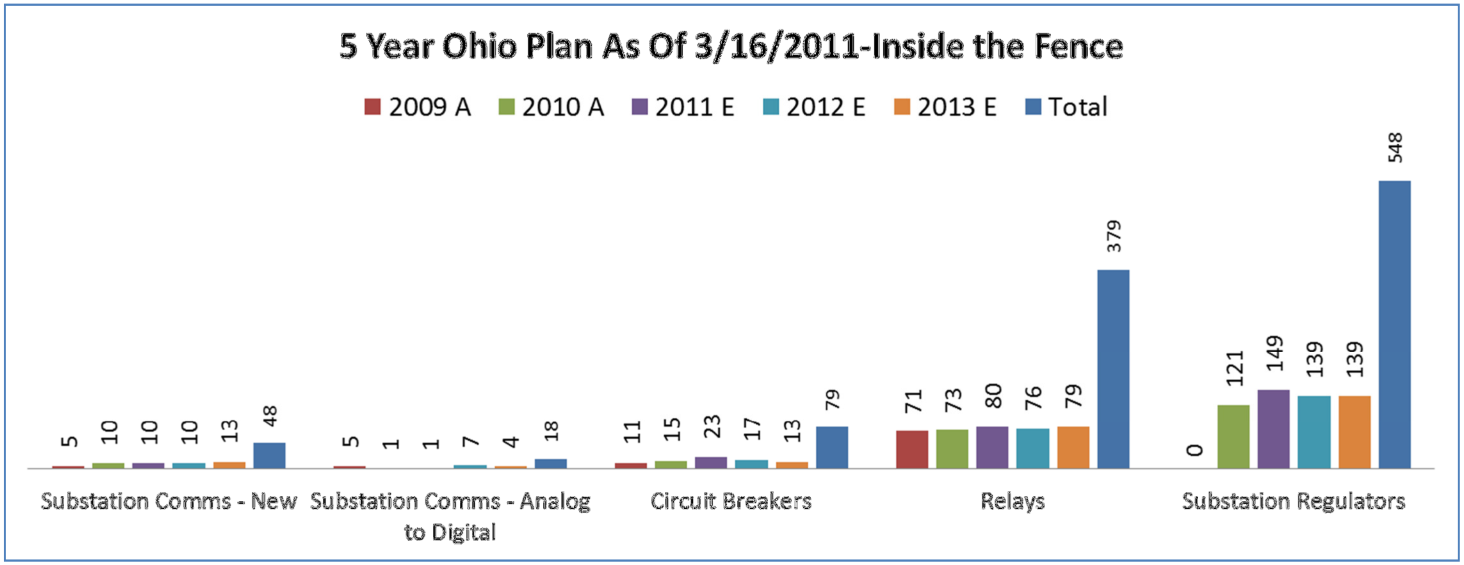


Figure A2.3 Field Audit Findings. Display readings from field (in blue) match archived data (in red)

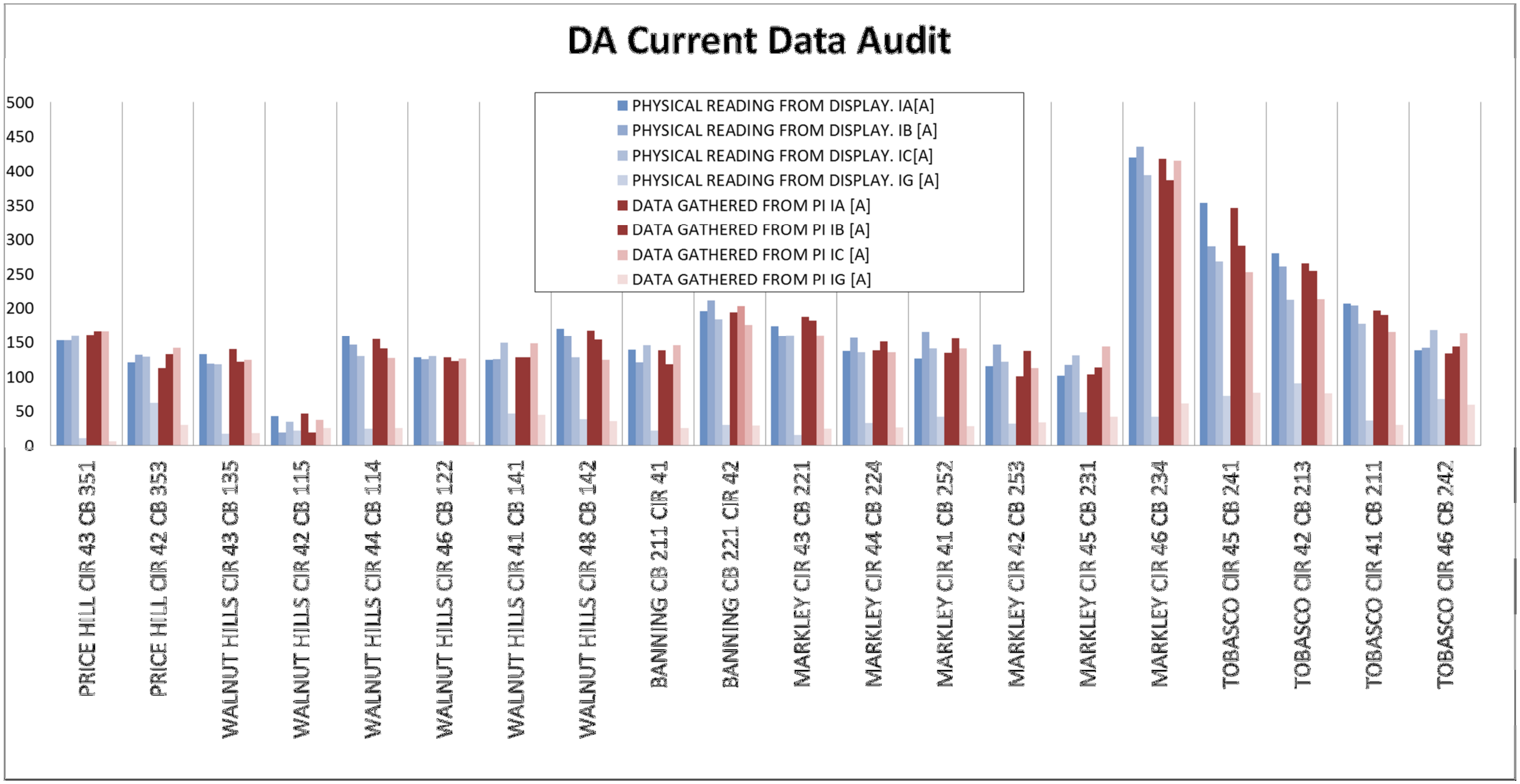
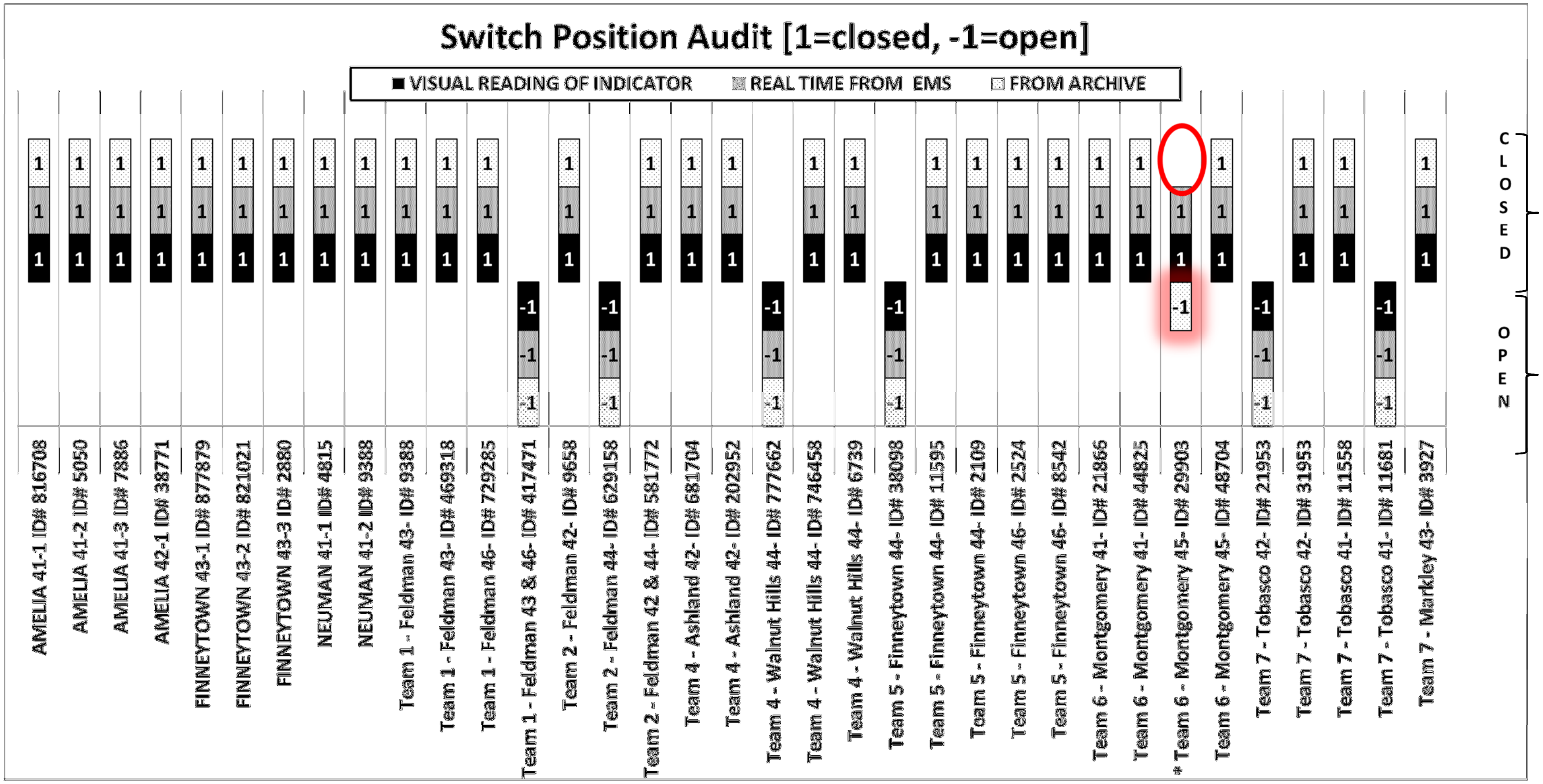


Figure A2.4. Field Audit Findings. All but one indicator reading match archived data



9 APPENDIX 3: GUIDELINES AND PRACTICES

9.1 Appendix 3-A – Conformity with the NISTIR 7628

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Requirement	Impact Level Allocation	Conformity Level
Access Control		
SG.AC-1 Access Control Policy and Procedures	Low / Moderate / High	....
SG.AC-2 Remote Access Policy and Procedures	Low / Moderate / High	....
SG.AC-3 Account Management	Low / Moderate / High	....
SG.AC-4 Access Enforcement	Low / Moderate / High	....
SG.AC-6 Separation of Duties	Moderate / High	....
SG.AC-7 Least Privilege	Moderate / High	....
SG.AC-8 Unsuccessful Login Attempts	Low / Moderate / High	....
SG.AC-9 Smart Grid Information System Use Notification	Low / Moderate / High	....
SG.AC-11 Concurrent Session Control	Moderate / High	....
SG.AC-12 Session Lock	Moderate / High	....
SG.AC-13 Remote Session Termination	Moderate / High	....
SG.AC-14 Permitted Actions without Identification or Authentication	Low / Moderate / High	....
SG.AC-15 Remote Access	Low / Moderate / High	....
SG.AC-16 Wireless Access Restrictions	Low / Moderate / High	....
SG.AC-17 Access Control for Portable and Mobile Devices	Low / Moderate / High	....
SG.AC-18 Use of External Information Control Systems	Low / Moderate / High	....
SG.AC-19 Control System Access Restrictions	Low / Moderate / High	....
SG.AC-20 Publicly Accessible Content	Low / Moderate / High	....
SG.AC-21 Passwords	Low / Moderate / High	....
Awareness and Training		
SG.AT-1 Awareness and Training Policy and Procedures	Low / Moderate / High	....
SG.AT-2 Security Awareness	Low / Moderate / High	....
SG.AT-3 Security Training	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.AT-4 Security Awareness and Training Records	Low / Moderate / High	....
SG.AT-6 Security Responsibility Testing	Low / Moderate / High	....
SG.AT-7 Planning Process Training	Low / Moderate / High	....
Audit and Accountability		
SG.AU-1 Audit and Accountability Policy and Procedures	Low / Moderate / High	....
SG.AU-2 Auditable Events	Low / Moderate / High	....
SG.AU-3 Content of Audit Records	Low / Moderate / High	....
SG.AU-4 Audit Storage Capacity	Low / Moderate / High	....
SG.AU-5 Response to Audit Processing Failures	Low / Moderate / High	....
SG.AU-6 Audit Monitoring, Analysis, and Reporting	Low / Moderate / High	....
SG.AU-7 Audit Reduction and Report Generation	Moderate / High	....
SG.AU-8 Time Stamps	Low / Moderate / High	....
SG.AU-9 Protection of Audit Information	Low / Moderate / High	....
SG.AU-10 Audit Record Retention	Low / Moderate / High	....
SG.AU-11 Conduct and Frequency of Audits	Low / Moderate / High	....
SG.AU-12 Auditor Qualification	Low / Moderate / High	....
SG.AU-13 Audit Tools	Low / Moderate / High	....
SG.AU-14 Security Policy Compliance	Low / Moderate / High	....
SG.AU-15 Audit Generation	Low / Moderate / High	....
SG.AU-16 Non-Repudiation	High	....
Security Assessment and Authorization		
SG.CA-1 Security Assessment and Authorization Policy and Procedures	Low / Moderate / High	....
SG.CA-2 Security Assessments	Low / Moderate / High	....
SG.CA-4 Smart Grid Information System Connections	Low / Moderate / High	....
SG.CA-5 Security Authorization to Operate	Low / Moderate / High	....
SG.CA-6 Continuous Monitoring	Low / Moderate / High	....
Configuration Management		
SG.CM-1 Configuration Management Policy and Procedures	Low / Moderate / High	....
SG.CM-2 Baseline Configuration	Low / Moderate / High	....
SG.CM-3 Configuration Change Control	Moderate / High	....
SG.CM-4 Monitoring Configuration Changes	Low / Moderate / High	....
SG.CM-5 Access Restrictions for Configuration Change	Moderate / High	....
SG.CM-6 Configuration Settings	Low / Moderate / High	....
SG.CM-7 Configuration for Least Functionality	Low / Moderate / High	....
SG.CM-8 Component Inventory	Low / Moderate / High	....
SG.CM-9 Addition, Removal, and Disposal of Equipment	Low / Moderate / High	....
SG.CM-10 Factory Default Settings Management	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.CM-11 Configuration Management Plan	Low / Moderate / High	
Continuity of Operations		
SG.CP-1 Continuity of Operations Policy and Procedures	Low / Moderate / High	
SG.CP-2 Continuity of Operations Plan	Low / Moderate / High	
SG.CP-3 Continuity of Operations Roles and Responsibilities	Low / Moderate / High	
SG.CP-4 Continuity of Operations Training	Low / Moderate / High	
SG.CP-5 Continuity of Operations Plan Testing	Low / Moderate / High	
SG.CP-6 Continuity of Operations Plan Update	Low / Moderate / High	
SG.CP-7 Alternate Storage Sites	Moderate / High	
SG.CP-8 Alternate Telecommunication Services	Moderate / High	
SG.CP-9 Alternate Control Center	Moderate / High	
SG.CP-10 Smart Grid Information System Recovery and Reconstitution	Low / Moderate / High	
SG.CP-11 Fail-Safe Response	High	
Identification and Authentication		
SG.IA-1 Identification and Authentication Policy and Procedures	Low / Moderate / High	
SG.IA-2 Identifier Management	Low / Moderate / High	
SG.IA-3 Authenticator Management	Low / Moderate / High	
SG.IA-4 User Identification and Authentication	Low / Moderate / High	
SG.IA-5 Device Identification and Authentication	Moderate / High	
SG.IA-6 Authenticator Feedback	Low / Moderate / High	
Information and Document Management		
SG.ID-1 Information and Document Management Policy and Procedures	Low / Moderate / High	
SG.ID-2 Information and Document Retention	Low / Moderate / High	
SG.ID-3 Information Handling	Low / Moderate / High	
SG.ID-4 Information Exchange	Low / Moderate / High	
Incident Response		
SG.IR-1 Incident Response Policy and Procedures	Low / Moderate / High	
SG.IR-2 Incident Response Roles and Responsibilities	Low / Moderate / High	
SG.IR-3 Incident Response Training	Low / Moderate / High	
SG.IR-4 Incident Response Testing and Exercises	Low / Moderate / High	
SG.IR-5 Incident Handling	Low / Moderate / High	
SG.IR-6 Incident Monitoring	Low / Moderate / High	
SG.IR-7 Incident Reporting	Low / Moderate / High	
SG.IR-8 Incident Response Investigation and Analysis	Low / Moderate / High	
SG.IR-9 Corrective Action	Low / Moderate / High	
SG.IR-10 Smart Grid Information System Backup	Low / Moderate / High	
SG.IR-11 Coordination of Emergency Response	Low / Moderate / High	

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
Smart Grid Information System Development and Maintenance		
SG.MA-1 Smart Grid Information System Maintenance Policy and Procedures	Low / Moderate / High	....
SG.MA-2 Legacy Smart Grid Information System Upgrades	Low / Moderate / High	....
SG.MA-3 Smart Grid Information System Maintenance	Low / Moderate / High	....
SG.MA-4 Maintenance Tools	Low / Moderate / High	....
SG.MA-5 Maintenance Personnel	Low / Moderate / High	....
SG.MA-6 Remote Maintenance	Low / Moderate / High	....
SG.MA-7 Timely Maintenance	Low / Moderate / High	....
Media Protection		
SG.MP-1 Media Protection Policy and Procedures	Low / Moderate / High	....
SG.MP-2 Media Sensitivity Level	Low / Moderate / High	....
SG.MP-3 Media Marking	Moderate / High	....
SG.MP-4 Media Storage	Low / Moderate / High	....
SG.MP-5 Media Transport	Low / Moderate / High	....
SG.MP-6 Media Sanitization and Disposal	Low / Moderate / High	....
Physical and Environmental Security		
SG.PE-1 Physical and Environmental Security Policy and Procedures	Low / Moderate / High	....
SG.PE-2 Physical Access Authorizations	Low / Moderate / High	....
SG.PE-3 Physical Access	Low / Moderate / High	....
SG.PE-4 Monitoring Physical Access	Low / Moderate / High	....
SG.PE-5 Visitor Control	Low / Moderate / High	....
SG.PE-6 Visitor Records	Low / Moderate / High	....
SG.PE-7 Physical Access Log Retention	Low / Moderate / High	....
SG.PE-8 Emergency Shutoff Protection	Low / Moderate / High	....
SG.PE-9 Emergency Power	Low / Moderate / High	....
SG.PE-10 Delivery and Removal	Low / Moderate / High	....
SG.PE-11 Alternate Work Site	Low / Moderate / High	....
SG.PE-12 Location of Smart Grid Information System Assets	Low / Moderate / High	....
Planning		
SG.PL-1 Strategic Planning Policy and Procedures	Low / Moderate / High	....
SG.PL-2 Smart Grid Information System Security Plan	Low / Moderate / High	....
SG.PL-3 Rules of Behavior	Low / Moderate / High	....
SG.PL-4 Privacy Impact Assessment	Low / Moderate / High	....
SG.PL-5 Security-Related Activity Planning	Moderate / High	....
Security Program Management		
SG.PM-1 Security Policy and Procedures	Low / Moderate / High	....
SG.PM-2 Security Program Plan	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.PM-3 Senior Management Authority	Low / Moderate / High	....
SG.PM-4 Security Architecture	Low / Moderate / High	....
SG.PM-5 Risk Management Strategy	Low / Moderate / High	....
SG.PM-6 Security Authorization to Operate Process	Low / Moderate / High	....
SG.PM-7 Mission/Business Process Definition	Low / Moderate / High	....
SG.PM-8 Management Accountability	Low / Moderate / High	....
Personnel Security		
SG.PS-1 Personnel Security Policy and Procedures	Low / Moderate / High	....
SG.PS-2 Position Categorization	Low / Moderate / High	....
SG.PS-3 Personnel Screening	Low / Moderate / High	....
SG.PS-4 Personnel Termination	Low / Moderate / High	....
SG.PS-5 Personnel Transfer	Low / Moderate / High	....
SG.PS-6 Access Agreements	Low / Moderate / High	....
SG.PS-7 Contractor and Third-Party Personnel Security	Low / Moderate / High	....
SG.PS-8 Personnel Accountability	Low / Moderate / High	....
SG.PS-9 Personnel Roles	Low / Moderate / High	....
Risk Management and Assessment		
SG.RA-1 Risk Assessment Policy and Procedures	Low / Moderate / High	....
SG.RA-2 Risk Management Plan	Low / Moderate / High	....
SG.RA-3 Security Impact Level	Low / Moderate / High	....
SG.RA-4 Risk Assessment	Low / Moderate / High	....
SG.RA-5 Risk Assessment Update	Low / Moderate / High	....
SG.RA-6 Vulnerability Assessment and Awareness	Low / Moderate / High	....
Smart Grid Information System and Services Acquisition		
SG.SA-1 Smart Grid Information System and Services Acquisition Policy and Procedures	Low / Moderate / High	....
SG.SA-2 Security Policies for Contractors and Third Parties	Low / Moderate / High	....
SG.SA-3 Life-Cycle Support	Low / Moderate / High	....
SG.SA-4 Acquisitions	Low / Moderate / High	....
SG.SA-5 Smart Grid Information System Documentation	Low / Moderate / High	....
SG.SA-6 Software License Usage Restrictions	Low / Moderate / High	....
SG.SA-7 User-Installed Software	Low / Moderate / High	....
SG.SA-8 Security Engineering Principles	Low / Moderate / High	....
SG.SA-9 Developer Configuration Management	Low / Moderate / High	....
SG.SA-10 Developer Security Testing	Low / Moderate / High	....
SG.SA-11 Supply Chain Protection	Low / Moderate / High	....
Smart Grid Information System and Communication Protection		
SG.SC-1 Smart Grid Information System and Communication Protection Policy and Procedures	Low / Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
SG.SC-3 Security Function Isolation	Low / Moderate / High	....
SG.SC-5 Denial-of-Service Protection	Low / Moderate / High	....
SG.SC-6 Resource Priority	High	....
SG.SC-7 Boundary Protection	Low / Moderate / High	....
SG.SC-8 Communication Integrity	Moderate / High	....
SG.SC-9 Communication Confidentiality	Moderate / High	....
SG.SC-11 Cryptographic Key Establishment and Management	Low / Moderate / High	....
SG.SC-12 Use of Validated Cryptography	Low / Moderate / High	....
SG.SC-13 Collaborative Computing	Low / Moderate / High	....
SG.SC-15 Public Key Infrastructure Certificates	Low / Moderate / High	....
SG.SC-16 Mobile Code	Moderate / High	....
SG.SC-17 Voice-Over Internet Protocol	Moderate / High	....
SG.SC-18 System Connections	Low / Moderate / High	....
SG.SC-19 Security Roles	Low / Moderate / High	....
SG.SC-20 Message Authenticity	Low / Moderate / High	....
SG.SC-21 Secure Name/Address Resolution Service	Low / Moderate / High	....
SG.SC-22 Fail in Known State	Moderate / High	....
SG.SC-26 Confidentiality of Information at Rest	Moderate / High	....
SG.SC-29 Application Partitioning	High	....
SG.SC-30 Smart Grid Information System Partitioning	Moderate / High	....
Smart Grid Information System and Information Integrity		
SG.SI-1 Smart Grid Information System and Information Integrity Policy and Procedures	Low / Moderate / High	....
SG.SI-2 Flaw Remediation	Low / Moderate / High	....
SG.SI-3 Malicious Code and Spam Protection	Low / Moderate / High	....
SG.SI-4 Smart Grid Information System Monitoring Tools and Techniques	Low / Moderate / High	....
SG.SI-5 Security Alerts and Advisories	Low / Moderate / High	....
SG.SI-6 Security Functionality Verification	Moderate / High	....
SG.SI-7 Software and Information Integrity	Moderate / High	....
SG.SI-8 Information Input Validation	Moderate / High	....
SG.SI-9 Error Handling	Low / Moderate / High	....
Cryptography and key management		
Key material and cryptographic operations protection	Moderate / High	....
Key material generation	Low / Moderate / High	....
Key material provisioning	High	....
Key material uniqueness, (e.g., key derivation secrets, managing secrets, pre-shared secrets)	Moderate / High	....
Revocation management	Low / Moderate / High	....
Credential span of control	Moderate / High	....

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Requirement	Impact Level Allocation	Conformity Level
Key and crypto lifecycles (supersession / revocation)	Low / Moderate / High	[redacted]
Key material Destruction	Moderate / High	[redacted]
Local autonomy (Availability Exclusively)	Moderate / High	[redacted]
Privacy		
Accuracy and Quality	N/A	[redacted]
Choice and Consent	N/A	[redacted]
Collection and Scope	N/A	[redacted]
Disclosure and Limiting Use	N/A	[redacted]
Individual Access	N/A	[redacted]
Management and Accountability	N/A	[redacted]
Notice and Purpose	N/A	[redacted]
Openness, Monitoring, and Challenging Compliance	N/A	[redacted]
Security and Safeguards	N/A	[redacted]
Use and Retention	N/A	[redacted]

9.2 Appendix 3-B – Potentiality of a Security Breach

The evaluation of the potentiality of a security breach to occur for each security requirement was performed by OKIOK based on its experience in the field of information security and on actual or theoretical security breaches observed throughout the various projects it performed over the years. This evaluation is unrelated to the Duke Energy Smart Grid deployment.

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
Access Control		
SG.AC-1 Access Control Policy and Procedures	GRC	[redacted]
SG.AC-2 Remote Access Policy and Procedures	GRC	[redacted]
SG.AC-3 Account Management	GRC	[redacted]
SG.AC-4 Access Enforcement	GRC	[redacted]
SG.AC-6 Separation of Duties	Common technical, Integrity	[redacted]
SG.AC-7 Least Privilege	Common technical, Integrity	[redacted]
SG.AC-8 Unsuccessful Login Attempts	Common technical, Integrity	[redacted]
SG.AC-9 Smart Grid Information System Use Notification	Common technical, Integrity	[redacted]
SG.AC-11 Concurrent Session Control	Unique technical requirement	[redacted]
SG.AC-12 Session Lock	Unique technical requirement	[redacted]
SG.AC-13 Remote Session Termination	Unique technical requirement	[redacted]
SG.AC-14 Permitted Actions without Identification or Authentication	Unique technical requirement	[redacted]
SG.AC-15 Remote Access	Unique technical requirement	[redacted]
SG.AC-16 Wireless Access Restrictions	Common technical, Confidentiality	[redacted]
SG.AC-17 Access Control for Portable and Mobile Devices	Common technical, Confidentiality	[redacted]
SG.AC-18 Use of External Information Control Systems	GRC	[redacted]
SG.AC-19 Control System Access Restrictions	GRC	[redacted]
SG.AC-20 Publicly Accessible Content	GRC	[redacted]
SG.AC-21 Passwords	Common technical, Integrity	[redacted]
Awareness and Training		
SG.AT-1 Awareness and Training Policy and Procedures	GRC	[redacted]
SG.AT-2 Security Awareness	GRC	[redacted]
SG.AT-3 Security Training	GRC	[redacted]
SG.AT-4 Security Awareness and Training Records	GRC	[redacted]
SG.AT-6 Security Responsibility Testing	GRC	[redacted]
SG.AT-7 Planning Process Training	GRC	[redacted]
Audit and Accountability		
SG.AU-1 Audit and Accountability Policy and Procedures	GRC	[redacted]
SG.AU-2 Auditable Events	Common technical, Integrity	[redacted]

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.AU-3 Content of Audit Records	Common technical, Integrity	[redacted]
SG.AU-4 Audit Storage Capacity	Common technical, Integrity	[redacted]
SG.AU-5 Response to Audit Processing Failures	GRC	[redacted]
SG.AU-6 Audit Monitoring, Analysis, and Reporting	GRC	[redacted]
SG.AU-7 Audit Reduction and Report Generation	GRC	[redacted]
SG.AU-8 Time Stamps	GRC	[redacted]
SG.AU-9 Protection of Audit Information	GRC	[redacted]
SG.AU-10 Audit Record Retention	GRC	[redacted]
SG.AU-11 Conduct and Frequency of Audits	GRC	[redacted]
SG.AU-12 Auditor Qualification	GRC	[redacted]
SG.AU-13 Audit Tools	GRC	[redacted]
SG.AU-14 Security Policy Compliance	GRC	[redacted]
SG.AU-15 Audit Generation	Common technical, Integrity	[redacted]
SG.AU-16 Non-Repudiation	Unique technical requirement	[redacted]
Security Assessment and Authorization		
SG.CA-1 Security Assessment and Authorization Policy and Procedures	GRC	[redacted]
SG.CA-2 Security Assessments	GRC	[redacted]
SG.CA-4 Smart Grid Information System Connections	GRC	[redacted]
SG.CA-5 Security Authorization to Operate	GRC	[redacted]
SG.CA-6 Continuous Monitoring	GRC	[redacted]
Configuration Management		
SG.CM-1 Configuration Management Policy and Procedures	GRC	[redacted]
SG.CM-2 Baseline Configuration	GRC	[redacted]
SG.CM-3 Configuration Change Control	GRC	[redacted]
SG.CM-4 Monitoring Configuration Changes	GRC	[redacted]
SG.CM-5 Access Restrictions for Configuration Change	GRC	[redacted]
SG.CM-6 Configuration Settings	GRC	[redacted]
SG.CM-7 Configuration for Least Functionality	Common technical, Integrity	[redacted]
SG.CM-8 Component Inventory	Common technical, Integrity	[redacted]
SG.CM-9 Addition, Removal, and Disposal of Equipment	GRC	[redacted]
SG.CM-10 Factory Default Settings Management	GRC	[redacted]
SG.CM-11 Configuration Management Plan	GRC	[redacted]
Continuity of Operations		
SG.CP-1 Continuity of Operations Policy and Procedures	GRC	[redacted]
SG.CP-2 Continuity of Operations Plan	GRC	[redacted]
SG.CP-3 Continuity of Operations Roles and Responsibilities	GRC	[redacted]
SG.CP-4 Continuity of Operations Training	GRC	[redacted]

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.CP-5 Continuity of Operations Plan Testing	GRC	[redacted]
SG.CP-6 Continuity of Operations Plan Update	GRC	[redacted]
SG.CP-7 Alternate Storage Sites	GRC	[redacted]
SG.CP-8 Alternate Telecommunication Services	GRC	[redacted]
SG.CP-9 Alternate Control Center	GRC	[redacted]
SG.CP-10 Smart Grid Information System Recovery and Reconstitution	GRC	[redacted]
SG.CP-11 Fail-Safe Response	GRC	[redacted]
Identification and Authentication		
SG.IA-1 Identification and Authentication Policy and Procedures	GRC	[redacted]
SG.IA-2 Identifier Management	GRC	[redacted]
SG.IA-3 Authenticator Management	GRC	[redacted]
SG.IA-4 User Identification and Authentication	Unique technical requirement	[redacted]
SG.IA-5 Device Identification and Authentication	Unique technical requirement	[redacted]
SG.IA-6 Authenticator Feedback	Unique technical requirement	[redacted]
Information and Document Management		
SG.ID-1 Information and Document Management Policy and Procedures	GRC	[redacted]
SG.ID-2 Information and Document Retention	GRC	[redacted]
SG.ID-3 Information Handling	GRC	[redacted]
SG.ID-4 Information Exchange	GRC	[redacted]
Incident Response		
SG.IR-1 Incident Response Policy and Procedures	GRC	[redacted]
SG.IR-2 Incident Response Roles and Responsibilities	GRC	[redacted]
SG.IR-3 Incident Response Training	GRC	[redacted]
SG.IR-4 Incident Response Testing and Exercises	GRC	[redacted]
SG.IR-5 Incident Handling	GRC	[redacted]
SG.IR-6 Incident Monitoring	GRC	[redacted]
SG.IR-7 Incident Reporting	GRC	[redacted]
SG.IR-8 Incident Response Investigation and Analysis	GRC	[redacted]
SG.IR-9 Corrective Action	GRC	[redacted]
SG.IR-10 Smart Grid Information System Backup	GRC	[redacted]
SG.IR-11 Coordination of Emergency Response	GRC	[redacted]
Smart Grid Information System Development and Maintenance		
SG.MA-1 Smart Grid Information System Maintenance Policy and Procedures	GRC	[redacted]
SG.MA-2 Legacy Smart Grid Information System Upgrades	GRC	[redacted]
SG.MA-3 Smart Grid Information System Maintenance	GRC	[redacted]
SG.MA-4 Maintenance Tools	GRC	[redacted]
SG.MA-5 Maintenance Personnel	GRC	[redacted]

Dark Gray = Unique Technical Requirement Light Gray = Common Technical Requirement White = Common Governance, Risk and Compliance (GRC)		
Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.MA-6 Remote Maintenance	GRC	[redacted]
SG.MA-7 Timely Maintenance	GRC	[redacted]
Media Protection		
SG.MP-1 Media Protection Policy and Procedures	GRC	[redacted]
SG.MP-2 Media Sensitivity Level	GRC	[redacted]
SG.MP-3 Media Marking	GRC	[redacted]
SG.MP-4 Media Storage	GRC	[redacted]
SG.MP-5 Media Transport	GRC	[redacted]
SG.MP-6 Media Sanitization and Disposal	GRC	[redacted]
Physical and Environmental Security		
SG.PE-1 Physical and Environmental Security Policy and Procedures	GRC	[redacted]
SG.PE-2 Physical Access Authorizations	GRC	[redacted]
SG.PE-3 Physical Access	GRC	[redacted]
SG.PE-4 Monitoring Physical Access	GRC	[redacted]
SG.PE-5 Visitor Control	GRC	[redacted]
SG.PE-6 Visitor Records	GRC	[redacted]
SG.PE-7 Physical Access Log Retention	GRC	[redacted]
SG.PE-8 Emergency Shutoff Protection	GRC	[redacted]
SG.PE-9 Emergency Power	GRC	[redacted]
SG.PE-10 Delivery and Removal	GRC	[redacted]
SG.PE-11 Alternate Work Site	GRC	[redacted]
SG.PE-12 Location of Smart Grid Information System Assets	GRC	[redacted]
Planning		
SG.PL-1 Strategic Planning Policy and Procedures	GRC	[redacted]
SG.PL-2 Smart Grid Information System Security Plan	GRC	[redacted]
SG.PL-3 Rules of Behavior	GRC	[redacted]
SG.PL-4 Privacy Impact Assessment	GRC	[redacted]
SG.PL-5 Security-Related Activity Planning	GRC	[redacted]
Security Program Management		
SG.PM-1 Security Policy and Procedures	GRC	[redacted]
SG.PM-2 Security Program Plan	GRC	[redacted]
SG.PM-3 Senior Management Authority	GRC	[redacted]
SG.PM-4 Security Architecture	GRC	[redacted]
SG.PM-5 Risk Management Strategy	GRC	[redacted]
SG.PM-6 Security Authorization to Operate Process	GRC	[redacted]
SG.PM-7 Mission/Business Process Definition	GRC	[redacted]
SG.PM-8 Management Accountability	GRC	[redacted]

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
Personnel Security		
SG.PS-1 Personnel Security Policy and Procedures	GRC	[redacted]
SG.PS-2 Position Categorization	GRC	[redacted]
SG.PS-3 Personnel Screening	GRC	[redacted]
SG.PS-4 Personnel Termination	GRC	[redacted]
SG.PS-5 Personnel Transfer	GRC	[redacted]
SG.PS-6 Access Agreements	GRC	[redacted]
SG.PS-7 Contractor and Third-Party Personnel Security	GRC	[redacted]
SG.PS-8 Personnel Accountability	GRC	[redacted]
SG.PS-9 Personnel Roles	GRC	[redacted]
Risk Management and Assessment		
SG.RA-1 Risk Assessment Policy and Procedures	GRC	[redacted]
SG.RA-2 Risk Management Plan	GRC	[redacted]
SG.RA-3 Security Impact Level	GRC	[redacted]
SG.RA-4 Risk Assessment	GRC	[redacted]
SG.RA-5 Risk Assessment Update	GRC	[redacted]
SG.RA-6 Vulnerability Assessment and Awareness	GRC	[redacted]
Smart Grid Information System and Services Acquisition		
SG.SA-1 Smart Grid Information System and Services Acquisition Policy and Procedures	GRC	[redacted]
SG.SA-2 Security Policies for Contractors and Third Parties	GRC	[redacted]
SG.SA-3 Life-Cycle Support	GRC	[redacted]
SG.SA-4 Acquisitions	GRC	[redacted]
SG.SA-5 Smart Grid Information System Documentation	GRC	[redacted]
SG.SA-6 Software License Usage Restrictions	GRC	[redacted]
SG.SA-7 User-Installed Software	GRC	[redacted]
SG.SA-8 Security Engineering Principles	GRC	[redacted]
SG.SA-9 Developer Configuration Management	GRC	[redacted]
SG.SA-10 Developer Security Testing	Common technical, Integrity	[redacted]
SG.SA-11 Supply Chain Protection	Common technical, Integrity	[redacted]
Smart Grid Information System and Communication Protection		
SG.SC-1 Smart Grid Information System and Communication Protection Policy and Procedures	GRC	[redacted]
SG.SC-3 Security Function Isolation	Unique technical requirement	[redacted]
SG.SC-5 Denial-of-Service Protection	Unique technical requirement	[redacted]
SG.SC-6 Resource Priority	Unique technical requirement	[redacted]
SG.SC-7 Boundary Protection	Unique technical requirement	[redacted]
SG.SC-8 Communication Integrity	Unique technical requirement	[redacted]
SG.SC-9 Communication Confidentiality	Unique technical requirement	[redacted]

Dark Gray = Unique Technical Requirement   Light Gray = Common Technical Requirement
White = Common Governance, Risk and Compliance (GRC)

Smart Grid Security Requirement	Category	Potentiality of a Security Breach
SG.SC-11 Cryptographic Key Establishment and Management	Common technical, Confidentiality	[redacted]
SG.SC-12 Use of Validated Cryptography	Common technical, Confidentiality	[redacted]
SG.SC-13 Collaborative Computing	GRC	[redacted]
SG.SC-15 Public Key Infrastructure Certificates	Common technical, Confidentiality	[redacted]
SG.SC-16 Mobile Code	Common technical, Confidentiality	[redacted]
SG.SC-17 Voice-Over Internet Protocol	Unique technical requirement	[redacted]
SG.SC-18 System Connections	Common technical, Confidentiality	[redacted]
SG.SC-19 Security Roles	Common technical, Confidentiality	[redacted]
SG.SC-20 Message Authenticity	Common technical, Integrity	[redacted]
SG.SC-21 Secure Name/Address Resolution Service	Common technical, Integrity	[redacted]
SG.SC-22 Fail in Known State	Common technical, Integrity	[redacted]
SG.SC-26 Confidentiality of Information at Rest	Unique technical requirement	[redacted]
SG.SC-29 Application Partitioning	Unique technical requirement	[redacted]
SG.SC-30 Smart Grid Information System Partitioning	Common technical, Integrity	[redacted]
Smart Grid Information System and Information Integrity		
SG.SI-1 Smart Grid Information System and Information Integrity Policy and Procedures	GRC	[redacted]
SG.SI-2 Flaw Remediation	Common technical, Integrity	[redacted]
SG.SI-3 Malicious Code and Spam Protection	GRC	[redacted]
SG.SI-4 Smart Grid Information System Monitoring Tools and Techniques	GRC	[redacted]
SG.SI-5 Security Alerts and Advisories	GRC	[redacted]
SG.SI-6 Security Functionality Verification	GRC	[redacted]
SG.SI-7 Software and Information Integrity	Unique technical requirement	[redacted]
SG.SI-8 Information Input Validation	Common technical, Integrity	[redacted]
SG.SI-9 Error Handling	Common technical, Integrity	[redacted]
Cryptography and key management		
Key material and cryptographic operations protection	N/A	[redacted]
Key material generation	N/A	[redacted]
Key material provisioning	N/A	[redacted]
Key material uniqueness, (e.g., key derivation secrets, managing secrets, pre-shared secrets)	N/A	[redacted]
Revocation management	N/A	[redacted]
Credential span of control	N/A	[redacted]
Key and crypto lifecycles (supersession / revocation)	N/A	[redacted]
Key material Destruction	N/A	[redacted]
Local autonomy (Availability Exclusively)	N/A	[redacted]

9.3 Appendix 3-C – Evaluation of Common Vulnerabilities Acknowledgement

[redacted]

9.4 Appendix 3-D – Potentiality of a Security Breach vs. Conformity

Family	[redacted]								
Access Control	[redacted]								
Awareness and Training	[redacted]								
Audit and Accountability	[redacted]								
Security Assessment and Authorization	[redacted]								
Configuration Management	[redacted]								
Continuity of Operations	[redacted]								
Identification and Authentication	[redacted]								
Information and Document Management	[redacted]								
Incident Response	[redacted]								
Smart Grid Information System Development and Maintenance	[redacted]								
Media Protection	[redacted]								
Physical and Environmental Security	[redacted]								
Planning	[redacted]								
Security Program Management	[redacted]								
Personnel Security	[redacted]								
Risk Management and Assessment	[redacted]								
Smart Grid Information System and Services Acquisition	[redacted]								
Smart Grid Information System and Communication Protection	[redacted]								
Smart Grid Information System and Information Integrity	[redacted]								
Cryptography and key management	[redacted]								

10 APPENDIX 4: TIME-DIFFERENTIATED BILL DATA

In the evaluation of Time Differentiated Bill accuracy, bill types TDAM and TD-LITE were evaluated.

TDAM rates consist of On Peak, Shoulder and Off Peak pricing tiers for both winter and summer periods. The TDAM summer period is defined as June 1 through September 30. The TDAM winter period is defined as October 1 through May 31.

TD-LITE rates consist of On Peak and Off Peak pricing tiers for both winter and summer periods and Off Peak rates for spring and autumn periods. The summer period is defined as June 1 through September 30. The winter period is defined as December 1 through February 28 (29th if Leap Year). All other days are defined as spring or autumn. During the time TD-LITE rates were analyzed, all customer bills occurred during the spring period

.

Service Point	Bill Type	Off-Peak KWH Bill	Off-Peak KWH Data	On-Peak KWH Bill	On-Peak KWH Data	Shoulder KWH Bill	Shoulder KWH Data
68	TDAM	208.742	208.742	203.463	203.463	89.055	89.055
2	TDAM	227.098	227.098	131.953	131.953	54.391	54.391
12	TDAM	228.773	228.773	121.759	121.759	49.428	49.428
13	TDAM	340.961	340.961	232.956	232.956	71.576	71.576
23	TDAM	171.621	171.621	89.764	89.764	28.773	28.773
42	TDAM	293.806	293.806	130.626	130.626	46.33	46.33
52	TDAM	236.803	236.803	106.598	106.598	42.187	42.187
53	TDAM	73.398	73.398	35.603	35.603	15.36	15.36
54	TDAM	128.544	128.544	57.984	57.984	22.512	22.512
55	TDAM	131.473	131.473	74.009	74.009	21.86	21.86
56	TDAM	295.971	295.971	132.631	132.631	47.657	47.657
57	TDAM	233.531	233.531	123.025	123.025	43.9	43.9
1000277	TD-LITE	657.822	657.822	NA	NA	NA	NA
1000278	TD-LITE	967.989	967.989	NA	NA	NA	NA
1000279	TD-LITE	356.167	356.167	NA	NA	NA	NA
1000282	TD-LITE	1151.372	1151.372	NA	NA	NA	NA
1000284	TD-LITE	339.568	339.568	NA	NA	NA	NA
1000288	TD-LITE	1519.229	1519.229	NA	NA	NA	NA
1000290	TD-LITE	1252.964	1252.964	NA	NA	NA	NA
1000292	TD-LITE	801.402	801.402	NA	NA	NA	NA
1000302	TD-LITE	569.051	569.051	NA	NA	NA	NA
1000313	TD-LITE	297.537	297.537	NA	NA	NA	NA
1000374	TD-LITE	397.371	397.371	NA	NA	NA	NA
1000377	TD-LITE	479.79	479.79	NA	NA	NA	NA
1000382	TD-LITE	163.69	163.69	NA	NA	NA	NA

11 APPENDIX 5: SMART METER DATA

The following meters were selected for the change out process. Load profile and scalar data was downloaded from each meter and compared to the electric meter data head end, EDMS and CMS systems. The time stamped usage data from every meter was accurate in each system for both load profile and scalar data.

Meter Serial Numbers	Head End		EDMS	CMS	
	Load Profile	Scalar	Load Profile	Scalar	Scalar
1N5100055531GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000022457GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047752GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047082GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000021200GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000025105GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000015357GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100036623GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026309GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100099638GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100053077GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026398GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011223GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011815GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000013766GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011577GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100037075GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000022556GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100037411GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047803GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100054149GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100056126GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100040684GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100044234GZ008	Accurate	Accurate	Accurate	Accurate	Accurate

Meter Serial Numbers	Head End		EDMS	CMS	
	Load Profile	Scalar	Load Profile	Scalar	Scalar
1N5000012893GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011233GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100057176GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000015622GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000011822GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100053330GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100042933GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100040818GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100044275GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000012084GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000022690GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047772GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100045662GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100047716GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026092GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026091GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100036702GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100039844GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100038865GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100056272GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5000026321GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100056250GZ008	Accurate	Accurate	Accurate	Accurate	Accurate
1N5100049983GZ008	Accurate	Accurate	Accurate	Accurate	Accurate

12 APPENDIX 6: REFERENCE LIST

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13 APPENDIX 7: INPUTS AND ASSUMPTIONS

Input/Assumption	Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Average hourly consumption per customer	kWh	3.4457		3.2689							
Annual electric energy growth rate	%	[redacted]									
Annual electric demand growth rate	%	[redacted]									
Weighted average electric price/kWh (non-fuel)	$/kWh	[redacted]									
Weighted average fuel price/kWh	$/kWh	[redacted]									
Fuel price annual growth rate	%	[redacted]									
COE impact by EPA regulations	%	0	0	0	0	0	0	0	0	4	0
Electric Meter Accuracy Improvement (Smart vs. Traditional)	%	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180
Cumulative Residential Electric Meter Deployment	%	6	8	19	42	66	84	100	100	100	100
Annual Electric Meter Deployment	%	6	2	11	23	23	18	16	NA	NA	NA
Cumulative Gas Meter/Module Deployment	%	5	9	22	47	70	93	100	100	100	100
Annual Gas Meter/Module Deployment	%	5	4	13	25	23	23	7	NA	NA	NA
Cumulative IVVC hardware/communications Deployment*	%	0	1	1	1	34	67	100	100	100	100
Cumulative DMS software phases/Deployment*	%	0	1	1	1	1	50	100	100	100	100
Cumulative Self-Healing Deployment	%	0	0	10	33	57	80	100	100	100	100
Cumulative Sectionalizing Deployment	%	0	0	21	45	61	80	100	100	100	100
Weighted Average Cost of Capital	%	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60
Annual Inflation Rate '09-'17	%		2.50	2.50	2.50	2.50	3.00	3.00	3.00	3.00	3.00

*VR/LTC/Capacitor Bank hardware/communications and IVVC Algorithms are being tested in three unique IVVC pilots (i.e. 1% in 2009-2012).

14 APPENDIX 8: METER ACCURACY WEIGHTING

The determination of the average percentage registration involves the characteristics of the meter and the loading. The percentage registration of a watt-hour meter is, in general, different at light loads than at full loads. The accuracy of meters is more closely associated with the full load (30 amps) because that is when most power is consumed. The light load (3 amps) test for accuracy is only representative of the meter's performance at very small load conditions. Therefore, when making accuracy calculations one uses a weighted average since it is more indicative of customer usage patterns and in-service meter performance.

This method of calculating average accuracy complies with The American National Standard Code for Electricity Metering ANSI C12.1-2001 (section 5) is the standard method for calculating average accuracy based on a generic load. This method is consistent with the reporting data to the Staff.

14.1 Operational Benefit 8) Meter Accuracy Improvement Assumptions:

Average percentage registration is the weighted average of the percentage registration at light load (LL) and at full load (FL). The Accuracy improvement is the difference between weighted average percent registration for smart meters and traditional meters.

- High Case: 0.3% increase with smart meters
- Giving the FL registration a weight of 4X: Weighted Percentage Registration = (4*FL + LL)/5
- Duke Accuracy Measurements, generic load (ANSI C12.1)
- Mid Case: 0.18% increase with smart meters
- Giving the FL registration a weight of 6.48X: Weighted Percentage Registration = (6.48*FL + LL)/7.48
- MetaVu Accuracy Measurement, Duke Energy Ohio Average Load
  - Low Case: 0.17% increase with smart meters
  - Giving the FL registration a weight of 6.48X: Weighted Percentage Registration = (4*FL + LL)/5
  - MetaVu Accuracy Measurement, Duke Energy Ohio Average Load

See Table A9.1, Calculations A9.1 and Fig. A9.1 for a description of how MetaVu derived the average weighting based on an average hourly consumption of 3.2689kWh for Duke Energy Ohio. See Table A9.2 and Calculations A9.2 for a description of how MetaVu utilized meter accuracy measurements to derive the mid- and low case meter accuracy improvement.

Table A9.1

Average Hourly Consumption	I[A]	Voltage[V]	Power [kW]	Hours/day	Energy[kWh]/day	Weighting
[redacted]	13.62	240	3.2689	24	78.45	1
Full Test Load 1	30	240	7.2	9.44	67.97	6.48
Low Test Load 2	3	240	0.72	14.56	10.48	1.00
Test Load 1+2	NA	NA	NA	24	78.45	NA
Ave.(Load 1 and 2)	13.62	240	3.2689	NA	NA	NA

Calculations A9.1

Deriving Weighting

$$Hours_{Full\ Test\ load\ per\ day} = \frac{(Power_{Typical\ Average} - Power_{Test\ 3Amps}) \cdot 24hrs}{(Power_{Test\ 30Amps} - Power_{Test\ 3Amps})} = \frac{(3268.9W - 720W) \cdot 24hrs}{(7200W - 720W)} = 9.44hrs$$

$$Hours_{Low\ Test\ Load\ per\ day} = 24 - Hours_{Full\ Test\ load\ per\ day} = 24 - 9.44 = 14.56hrs$$

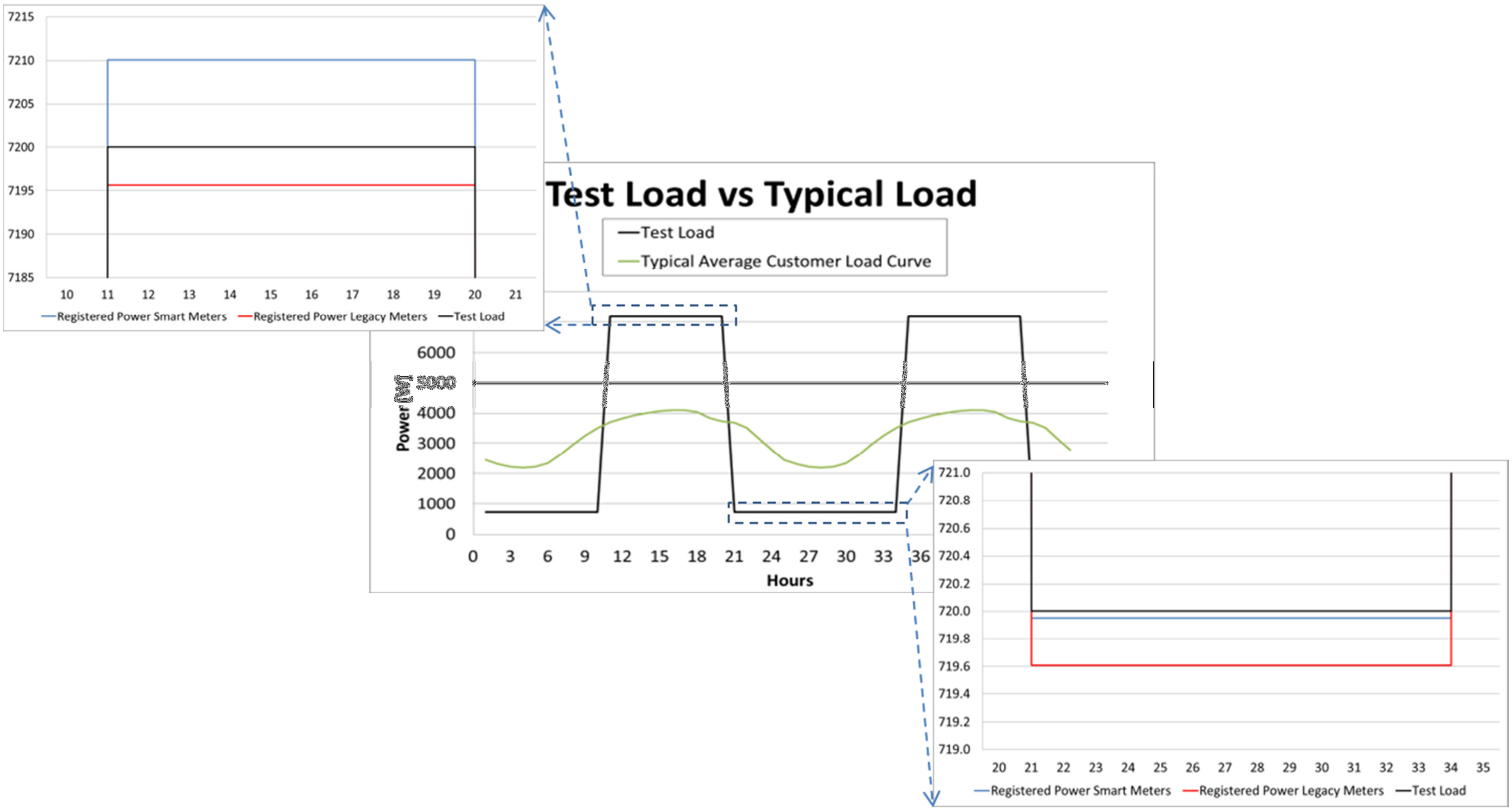
$$Energy_{Low\ Test\ Load\ per\ day} = Power_{Test\ 3Amps} \cdot Hours_{Low\ Test\ Load\ per\ day} = 0.72 * 14.56 = 10.48kWh$$

$$Energy_{Full\ Test\ Load\ per\ day} = Power_{Test\ 30Amps} \cdot Hours_{Full\ Test\ Load\ per\ day} = 7.2 * 9.44 = 67.97kWh$$

$$Weighting_{Full\ Test\ Load} = \frac{Energy_{Full\ Test\ Load\ per\ day}}{Energy_{Low\ Test\ Load\ per\ day}} = \frac{67.97}{10.48} = 6.48$$

Full Load (30Amps) Weighting	**6.48**

Figure A9.1



Test Load vs Typical Load
Test Load
Typical Average Customer Load Curve
Power [W]
Hours
0 1000 2000 3000 4000 5000 6000
0 3 6 9 12 15 18 21 24 27 30 33 36
7185 7190 7195 7200 7205 7210 7215
10 11 12 13 14 15 16 17 18 19 20 21
Registered Power Smart Meters
Registered Power Legacy Meters
Test Load
719.0 719.2 719.4 719.6 719.8 720.0 720.2 720.4 720.6 720.8 721.0
20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35
Registered Power Smart Meters
Registered Power Legacy Meters
Test Load

Table A9.2

	New Echelon, 23 Deg, Average Registration of 48			Old Traditional, 23 Deg, Average Registration of 48		
TEST LOAD [A]	TEST A	TEST C	Ave. (TEST A, TEST C)	TEST A	TEST C	Ave. (TEST A, TEST C)
30	100.118	100.161	100.139	99.943	99.935	99.939
3	99.973	100.013	99.993	100.062	99.830	99.946

Calculations A9.2

MID CASE % INCREASE

$$\frac{Weight_{30A} \cdot (Smart\ Reg_{30A} - Legacy\ Reg_{30A}) + Weight_{3A} \cdot (Smart\ Reg_{3A} - Legacy\ Reg_{3A})}{(Weight_{30A} + Weight_{3A})}$$

$$= \frac{6.48 \cdot (100.139 - 99.939) + 1.00 \cdot (99.993 - 99.946)}{(6.48 + 1.00)}$$

= 0.18%

LOW CASE % INCREASE

$$\frac{Weight_{30A,ANSI\ C12.1Duke} \cdot (Smart\ Reg_{30A} - Legacy\ Reg_{30A}) + Weight_{3A} \cdot (Smart\ Reg_{3A} - Legacy\ Reg_{3A})}{(Weight_{30A,Duke} + Weight_{3A})}$$

$$= \frac{4.00 \cdot (100.139 - 99.939) + 1.00 \cdot (99.993 - 99.946)}{(4.00 + 1.00)}$$

= 0.17%

15 APPENDIX 9: GLOSSARY

Advanced Metering Infrastructure (AMI): A metering system equipped with advanced two-way communications for electric and gas meters. The two-way communication allows for obtaining remote meter reads as well as the capability to perform certain remote operations. Duke's AMI allows remote off-cycle meter reading as well as remote connection/disconnection of service.

Assessors: Utility field technicians who investigate issues on the distribution grid.

Carrying Cost of Plant: The annuity or levelized cost of a system or plant, which may include depreciation expense, taxes and return on equity.

Capacitor bank: A collection of individual capacitor units that can be connected to or disconnected from each of the three phases; used to counteract reactive power from inductive loads.

Circuit Breaker (CB): An electrical switch typically found in substations utilized to protect a circuit from overloads or short circuits.

Circuit Breaker Protective Relays (CB Relays): Same as relays (See Relay).

Conservation Voltage Reduction (CVR): Reduces voltage and automatically improves power delivery efficiency and within required specifications.

Dispatchers: Utility distribution center staff members who delegate tasks to field technicians for the investigation and repair of issues involving the distribution grid.

Distribution Automation (DA): Automation of distribution devices, including two-way communications to some existing electronic devices on the distribution system and the addition of new electronic devices with two-way communications. DA consists of equipment both deployed on the distribution grid and within the substation.

Distribution Management System (DMS): DMS is a generic term for a software tool that consists of many integrated applications or plugins. DMS is an Energy Management System (EMS) that has the capability to monitor, control and automate the distribution portion of a power system. (See Energy Management System)

DSMore: A software package that takes inputs regarding specific supply costs (operating and purchase), demand within the specific jurisdiction, forecasted costs increases, and other factors and calculates the annual savings (energy, capacity, and CO_2) associated with modeled changes, such as lowering the voltage on the system.

Electric Load: The amount of power consumption on a circuit.

Energy Management System (EMS): An EMS is a generic term for a software tool that has the capability to monitor, control and automate an energy system. EMS may include transmission, generation and/or distribution portions. (See: Distribution Management System)

Electric Recloser: A circuit breaker enhanced with power quality measurements, analysis and communications.

Feeder: A physical conductor that feeds or supplies power to electric loads. The term feeder is used for the outgoing conductors from a substation. (See Electric Loads, Substation and Circuit)

Full-Time-Equivalent (FTE): The number of employees on full-time schedules plus the number of employees on part-time schedules converted to a full-time basis.

Hydraulic Recloser: Short for Circuit Breaker with hydraulic time delay. Some types of circuit breakers incorporate a *hydraulic time delay* feature using a viscous fluid.

Integrated Volt VAR Control (IVVC): Combined control of grid devices such as Load Tap Changer controllers and capacitor banks to provide unified voltage regulation and reactive power (VAR) flow control throughout the distribution line. (See System Voltage Reduction Strategy)

Intelligent Switches: An automated sectionalization device equipped with bi-directional communication capabilities.

Load Tap Changer (LTC): A device that can connect to the windings of a transformer to change the ratio of primary to secondary windings; changes the voltage relationship between the high and low sides of the transformer.

Load Tap Changer Controller (LTC Controller): A device that controls the load tap changer to allow for remote operation.

MAIFI: Momentary Average Interruption Frequency Index.

Oil-insulated Circuit Breaker (OCB): Traditional circuit breaker without smart grid capabilities.

OVR: Acronym for Overhead Recloser: (See Recloser)

Off-Cycle Reads: Meter readings conducted outside the typical monthly meter reading schedule. Off-cycle meter reads can be due to customers moving locations, requiring the utility to read the meter prior to the scheduled meter reading.

On-Cycle Reads: Meter readings conducted according to predetermined meter reading schedules.

Power Factor: The ratio of real power to apparent power in an AC system. It is considered the percent of total usable power.

Recloser: A circuit breaker equipped with a mechanism that can automatically close, open and reclose the breaker after it has been opened due to a fault. (See Electric Recloser).

Relay: A relay in the smart grid context refers to circuit breaker or switchgear controls that typically enhance a circuit breakers interrupting/reliability capability with protective features such as power quality measurements, analysis and communications.

Remote Terminal Unit (RTU): Microprocessor device that interfaces equipment in the field (such as DA equipment) with SCADA.

SCADA: See Supervisory Control and Data Acquisition

Sectionalization: The use of switching equipment to isolate circuits that have been damaged or contain faults.

Sectionalizer: Refers to the function of a switch, namely sectionalizing. Sectionalizers are typically overheard interrupting devices that increase the reliability metrics by isolating faults. Sectionalizers may be equipped with communications, but this is not a standard feature.

Self-Healing: A functionality of a Distribution Automation system, which utilizes automated switching to reconfigure the distribution grid and minimize the impact of outages.

Single Phase: One of three phases in an AC system. Single Phase portions of a distribution grid often refer to the 240V secondary side of a line transformer (see Tap Line).

Substation: A substation typically consists of one or more high-to-medium voltage transformers, circuit breakers and other switchgear. Smart grid-enhanced substations typically have one or more Voltage Regulators and/or Load Tap Changers with embedded Controls, and/or Protective Relays with Controls and Communications.

Supervisory Control and Data Acquisition (SCADA): A computer system used to monitor and control utility equipment.

Switch: A sectionalization device utilized in the distribution grid.

System Voltage Reduction Strategy: System (Distribution Grid) Voltage Reduction is often named Conservation Voltage Reduction (CVR) or Integrated Volt VAR Control (IVVC)

Tap Line: Low Voltage 240V line of the distribution grid.

Validation, Editing and Estimating (VEE): Processes to analyze and validate interval customer usage data.

Voltage Regulators: A “dimmer switch” in a substation that controls the voltage going to a feeder.

Voltage Regulator Controls: A device that remotely operates a Voltage Regulator and reports voltage regulator data.

16 APPENDIX 10: PROJECT PARTNER QUALIFICATIONS

16.1 MetaVu, Inc.

Meta Vu is a management, strategy, and valuation consulting firm that has been in practice since 2002. The Company has developed specific competencies and skill sets by helping clients understand the value of sustainable business practices and corresponding client performance as measured objectively against both defined and emerging standards and market-based best practices.

MetaVu has been particularly active in the Oil and Gas and Utility Sectors, focusing on energy's unique and central role as the nexus and barometer of operational efficiency and environmental performance. The Company's expertise in the utility industry is focused on renewable energy strategy, energy efficiency strategy, and the enabling capabilities of the smart grid. MetaVu's smart grid experience stems from recent and relevant project work:

- Benefit and Cost analyses of various AMI and DA components of a demonstration project of 46,000 premises
- Estimation of energy and demand benefits associated with various time-differentiated rates and advanced demand response devices in a study of 7,000 participants using enrollment mechanisms to simulate both voluntary and "default rate" implementation options
- Qualitative and quantitative research of electricity customers' perspectives on various smart grid capabilities and benefits, from time-differentiated rates and demand response to improved reliability and customer services
- Identification of opportunities to maximize smart grid benefits through organizational and operational change management practices, including strategy and structure, governance and process, data systems and tools, and resource development
- Meta-analysis of smart grid performance evaluation frameworks, including EPRI, PNNL, and NETL
- Examination of ARRA grant awards and smart grid applications from U.S. utilities BG&E, Duke Energy, OG&E, PG&E, SCE, and Xcel Energy

For more information on MetaVu, please visit the company's website at www.metavu.com.

16.2 Alliance Calibration

Alliance Calibration serves the aeronautical, defense, automotive, government, research, medical, pharmaceutical, energy, and power industries. Alliance Calibration is a mutual held trade name for Toolroom, Inc. and Raitz Services, Inc. Toolroom focuses on Mechanical and Dimensional services while Raitz specializes in the Process and Test market.

Alliance Calibration's services include dimensional & mechanical as well as process & test equipment calibration. Examples of dimensional & mechanical include gages, calipers, indicators, micrometers, plates, scales, rings, hardness testers, CMM' s, comparators, plugs, blocks, & protractors. Process & test equipment calibration services include pressure, vacuum, frequency, AC/DC power supplies, humidity, pH & conductivity, controllers, recorders, meters, meggers, hipots, thermocouples, RTD' s, timers, oscilloscopes, ovens, scales, & guns.

Alliance Calibration is ISO/IEC 17025:2005 accredited by Laboratory Accreditation Bureau (LAB) in the disciplines described, and all calibration staff holds certifications from the American Society for Quality. Alliance Calibration offers clients access to calibration results 24 hours per day, 365 days per year through its eTracking service.

16.3 OKIOK Data, Ltd.

OKIOK has been dedicated to the field of IT security since 1983 and has developed a unique expertise in designing, building and evaluating complex, secure systems involving communications, embedded software, cryptography, remote firmware upgrades etc. Over the years, OKIOK has pioneered several key concepts and developed strong competencies related to the core technologies that are the very foundation of modern AMI infrastructures.

Few firms can claim to be entirely dedicated and specialized within the field of information security and consequently, OKIOK, with close to 50 specialists and engineers, is recognized as one of the leading North American companies in this space. The diversity of OKIOK engagements and the expertise garnered over the years demonstrates a thorough knowledge of the challenges, problems, best-practices and solutions associated with security technologies.

OKIOK has successfully provided vision and project leadership for two major initiatives that led to the definition of corporate security architecture along with a 5 year security master plan for Hydro Quebec. These initiatives will help Hydro-Québec adopt a proactive security stance and meet the challenge of its upcoming AMI infrastructure deployment (potentially reaching 4.5 million units) as well as compliance to internal security standards, ISO 27002 and NERC CIP 02 to 09.