BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 141

In the Matter of:	)	**[PUBLIC]**
2014 Smart Grid Technology	)	**COMMENTS**
Plans	)	
	)	

COMMENTS OF NCSEA AND EDF

Pursuant to Rule R8-60.1(d), the North Carolina Sustainable Energy Association ("NCSEA") and the Environmental Defense Fund ("EDF") jointly submit the following comments on the smart grid technology plans ("SGT plans") submitted pursuant to Rule R8-60.1(b) by Duke Energy Carolinas, LLC, Duke Energy Progress, Inc. ("DEC" and "DEP" respectively, or "Duke" collectively), and Dominion North Carolina Power ("DNCP").

INTRODUCTION

It is undisputed that smart grid technologies offer numerous benefits to customers. As recognized by the Commission,

> advanced technologies under the smart grid umbrella have tremendous potential to improve service to electric customers. Such technologies promise greater reliability, more effective system operations, better customer information and improved planning. Some smart grid technology could provide the foundation for more effective and expanded EE and DSM programs by controlling appliances so that they use energy more effectively and by educating customers about their energy use. Some smart grid technologies will be needed to address the increased use of electric vehicles in the future.[1]

[1] *Order Declining to Adopt Federal Standards*, pp. 20-21, Commission Docket No. E-100, Sub 123 (18 December 2009).

Attached are letters from PlotWatt, a company based in Durham, and Mission:data, a national organization whose members include EnerNOC, Lucid, Nest, and PlotWatt.[2] Both see opportunities for customer savings that will become available as smart grid technologies are planned and deployed. As the two letters show, businesses based in North Carolina and national organizations dispute some of the assertions contained in the SGT plans filed by the utilities. As discussed further below, the utilities are familiar with filing plans for the implementation of smart grid technologies with regulatory bodies; subsidiaries of Duke Energy Corporation ("Duke Energy") have filed robust plans with regulators in Indiana and Ohio.[3] Given that North Carolina is the home state of Duke Energy, it would be reasonable to assume that the SGT plans filed by DEC and DEP would be Duke Energy's most robust plans. However, the SGT plans filed by Duke Energy's North Carolina operating companies are not its most robust plans; rather, as to content, the plans fail to comply with the rules established by the Commission and are therefore deficient.

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[2] *See generally*, **Exhibit A** (Letter from Luke Fishback, Chief Executive Officer and Founder, PlotWatt, Inc., to Chairman Edward S. Finley, Jr., Commissioner Don M. Bailey, Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner Susan Warren Rabon, and Commissioner James G. Patterson, North Carolina Utilities Commission (9 January 2015)); **Exhibit B** (Letter from Jim Hawley and Michael Murray, The Mission:data Coalition, Inc., to Chairman Edward S. Finley, Jr., Commissioner Don M. Bailey, Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner Susan Warren Rabon, and Commissioner James G. Patterson, North Carolina Utilities Commission (9 January 2015))

[3] *See generally*, **Exhibit C** (*Direct Testimony of Russell Lee Atkins*, Exhibit B-1, Indiana Utility Regulatory Commission Cause No. 44526 (29 August 2014), available at https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801bcab1); **Exhibit D** (*Direct Testimony of Christopher D. Kiergan*, Attachment CDK-1, Public Utilities Commission of Ohio Case No. 08-920-EL-SS0 (31 July 2008), available at http://dis.puc.state.oh.us/TiffToPDf/A1001001A08G31B72845E38927.pdf).

NCSEA's and EDF's joint comments are arranged as follows: First, NCSEA and EDF set forth their argument that the SGT plans filed by the utilities are deficient because they fail to provide adequate information on customer access to their energy consumption data, fail to provide cost-benefit analyses, and fail to provide adequate technology descriptions. Second, NCSEA and EDF request relief from the Commission, including requiring the utilities to file supplemental information to fully comply with the provisions of Rule R8-60.1 or hold a hearing on the adequacy of the SGT plans filed by the utilities and to initiate rulemaking to adopt clear data access policies.

ARGUMENT

The SGT plans filed by the utilities are facially deficient and fail to comply with Rule R8-60.1. Perhaps more importantly, the SGT plans filed by the utilities fail to provide enough information to inform the Commission as to whether the utilities are taking the steps necessary to enable customers to reap the benefits that smart grid technologies are capable of providing.

I. REQUIREMENTS OF RULE R8-60.1.

Rule R8-60.1(c)(7) directs the utilities to include in their SGT plans "[a] description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information." Subdivision (8) further directs the utilities to include "[a] description, if applicable, of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties." Rule R8-60.1(c)(4) directs the utilities to include in their SGT plans "[c]ost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses." Rule R8-60.1(c)(1) directs the utilities to include "[a] description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology."

II. THE SGT PLANS FILED BY THE UTILITIES FAIL TO ADEQUATELY ADDRESS ISSUES RELATED TO CUSTOMER ACCESS TO THEIR ENERGY CONSUMPTION DATA, AS REQUIRED BY RULE R8-60.1(c)(7) AND (8) AND AS DIRECTED IN COMMISSION DOCKET NO. E-100, SUB 137.

In response to the directives concerning how the utilities will transfer information between themselves and customers and how third parties will implement or utilize any portion of the technology, the utilities all failed to provide sufficient information. DEC states that its "AMI deployments in the Carolinas provide customers with previous day energy usage data," but fails to explain how customers access their data and the format in which data is provided to customers.[4] DEP notes that it collects data, but its filed SGT plan fails to even say if such data is accessible to customers.[5] DNCP states that "[c]ustomers may obtain their own usage information[,]" but its filed SGT plan fails to explain how customers may do so.[6] In short, none of the SGT plans filed by the utilities

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[4] *DEC and DEP 2014 Smart Grid Technology Plans*, p. 34, Commission Docket No. E-100, Sub 141 (1 October 2014) (hereinafter "*DEC 2014 SGT Plan*").

[5] "The meters are read every 4 hours to collect new data, and the data is stored in an operational database on the Duke network until it is transmitted to the customer billing system for billing." *DEC and DEP 2014 Smart Grid Technology Plans*, p. 28, Commission Docket No. E-100, Sub 141 (1 October 2014) (hereinafter "*DEP 2014 SGT Plan*").

[6] *DNCP's Smart Grid Technology Plan*, p. 8, Commission Docket No. E-100, Sub 141 (1 October 2014) (hereinafter "*DNCP 2014 SGT Plan*").

address "how the utility intends the technology to transfer information between [the utility] and the consumer[.]"[7]

Duke provides no response to Rule R8-60.1(c)(8), instead stating that "[n]o third-parties currently utilize any of the planned technologies, nor is customer information shared with any third-parties."[8] However, Duke's response, or lack thereof, is problematic for four main reasons:

First, the Commission indicated that it expects the utilities to include information about what customer usage data is being collected and how it will be accessed by customers and third parties. In addressing issues of what energy consumption data is being collected by the utilities and how customers access this data, the Commission wrote that it "is inclined to allow the IOUs to address these issues in their SGT reports to be filed on October 1, 2014. Those reports should provide information about the customer usage data currently being collected and contemplated to be collected."[9]

Second, as demonstrated by the attached letters, third parties utilize technologies, particularly the information on customer energy consumption that smart grid technologies are capable of collecting.[10] PlotWatt, for example, states:

> PlotWatt utilizes data and information from the utility's Advanced Metering Infrastructure ("AMI") meters to assist consumers in saving money. Data and information allows PlotWatt to deliver much-needed energy savings tools to consumers, including our patent-pending energy disaggregation service which enables homes and businesses to learn about their appliance-level energy usage and opportunities for savings. Our technology is currently installed in thousands of homes and small businesses around the world, saving our customers an[] average of 10-15% on energy bills. In

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[7] Rule R8-60.1(c)(7).

[8] *DEC 2014 SGT Plan, supra* note 4, p. 42; *DEP 2014 SGT Plan, supra* note 5, p. 38.

[9] *Order Requesting Additional Information and Declining to Initiate Rulemaking*, p. 12, Commission Docket No. E-100, Sub 137 (23 August 2013).

[10] **Exhibit A**; **Exhibit B**.

> service territories where utilities provide third-parties with access to meter-level data and information upon authorization by the consumer, PlotWatt is already delivering invaluable insight on energy consumption. . . . PlotWatt believes that the statement of Duke Energy Carolinas and Duke Energy Progress that "No third-parties currently utilize any of the planned technologies[]" is incorrect.[11]

Mission:data's letter contains similar assertions.[12] Clearly, numerous companies are actively utilizing smart grid technologies in other states, and are willing and able do so in North Carolina.

Third, Duke appears to misinterpret the temporal component of what this section of the rule is requiring. The Commission clearly expects information on "how third parties *will* implement or utilize" the smart grid technologies, but Duke's response is that no "third-parties *currently* utilize any of the planned technologies."[13] While NCSEA and EDF dispute the notion that no third-parties currently utilize these smart grid technologies, Duke clearly fails to comply with the rule because its response does not include any prospective information.

Fourth and finally, Duke appears to misunderstand the scope of what this rule is requiring. Despite its assertion that third parties do not utilize these technologies, Duke has in place procedures which, although NCSEA and EDF believe them to be inadequate, are designed to transfer customer-specific information from Duke to third parties and procedures for how customers authorize the release of such information. Given that the Commission believes "transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third

[11] **Exhibit A**, pp. 1-2.
[12] *See generally*, **Exhibit B**, pp. 2-3.
[13] Rule R8-60.1(c)(8) (emphasis added); *DEC 2014 SGT Plan*, *supra* note 4, p. 42; *DEP 2014 SGT Plan*, *supra* note 5, p. 38 (emphasis added).

parties[]" to be subsets of "how third parties will implement or utilize any portion of the technology," it is clear that Rule R8-60.1(c)(8) is applicable to Duke, and that a description of these procedures should have been included in the SGT plans filed by Duke.

In a different regard, the SGT plans filed by Duke fail to mention the Green Button Initiative, a federal data initiative related to energy designed to provide "consumers with secure access to their own personal . . . energy . . . data[.]"[14] Green Button is available to more than 60 million customers in the U.S., with 105 companies currently participating or committed to participate, including 35 utilities.[15] While DNCP is participating in Green Button, Duke makes no mention of the initiative in its filings, nor its rationale for deciding not to participate in the program.[16] Even though DNCP is participating, only customers on time-of-use rates can use Green Button to view their energy consumption data.[17] This means that in North Carolina, only 312 residential customers of the three companies can use Green Button to view their energy consumption data.[18]

Despite the directives of both Rule R8-60.1 and the Commission's order in Docket E-100, Sub 137, the utilities fail to include adequate "description[s] . . . of how third parties

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[14] John Teeter, The Green Button Initiative, National Institute of Standards and Technology, p. 2, https://services.greenbuttondata.org/library/presentations/Green_Button_Overview_Sept2014.pdf. "There are two flavors of Green Button – Green Button Download, which requires a user to manually download their usage data and upload it to third-party applications, and Green Button Connect, which lets the user authorize a third party to have consistent access to that user's data. While Green Button Download is a useful first step, it has limited use because the customer must manually download the data stream each time a comparison is required." **Exhibit B**, pp. 8-9.

[15] The Green Button Initiative, p. 4; Green Button, http://www.greenbuttondata.org.

[16] *DNCP 2014 SGT Plan*, *supra* note 6, p. 6.

[17] **Exhibit I** (*NCSEA DNCP DR2, Question No. 2-16*, Commission Docket No. E-100, Sub 141).

[18] **Exhibit J** (*NCSEA DNCP DR2, Question No. 2-17*, Commission Docket No. E-100, Sub 141).

will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties." Accordingly, the Commission is not adequately informed as to whether customers are receiving the benefits of greater access to energy consumption data that smart grid technologies provide.

III. THE SGT PLANS FILED BY THE UTILITIES FAIL TO INCLUDE COST-BENEFIT ANALYSES, AS REQUIRED BY RULE R8-60.1(c)(4), FAIL TO INCORPORATE THE ANALYSES PERFORMED IN THE INTEGRATED RESOURCE PLANS FILED IN THIS DOCKET, AND FAIL TO PROVIDE THE COMMISSION WITH THE SAME LEVEL OF INFORMATION AS WAS PROVIDED TO REGULATORY BODIES IN OTHER STATES, EVEN THOUGH THE UTILITIES HAVE DEVELOPED SOME COST-BENEFIT ANALYSES.

In response to the directive concerning cost-benefit analyses, the utilities provided no cost-benefit analyses whatsoever in their filed SGT plans. Costs were discussed at various points and benefits were discussed at differing points, but nowhere do the filed SGT plans contain cost-benefit analyses. Accordingly, the SGT plans filed by the utilities are necessarily deficient in this regard. The utilities may argue that there are no cost-benefit analyses in the filed SGT plans because there are no firmly scheduled deployment plans. This filing is intended to be a forecast, not a schedule or a summary of projects that have already been implemented. During the development of Rule R8-60.1, the Public Staff wrote that "the utilities routinely forecast events with varying degrees of certainty[] . . . These events, like smart grid technologies and their impacts, should be based on informed judgments."[19] The Commission cannot permit the utilities to circumvent or short-circuit

[19] *Public Staff's Reply Comments*, p. 3, Commission Docket No. E-100, Sub 126 (26 March 2010).

the rule, particularly given that the utilities appear to have done some cost-benefit analyses for their North Carolina service territories and that cost-benefit analyses done by utilities in other jurisdictions show that smart grid technologies provide a net benefit to customers.

The omission of cost-benefit analyses from the SGT plans filed by the utilities may be the result of confusion between the various parties as to how detailed an analysis of the costs and benefits of a particular piece of technology must be in order for it to be considered a cost-benefit analysis as the term is used in Rule R8-60.1(c)(4). In response to initial data requests seeking cost-benefit analyses, Duke referred NCSEA to the SGT plans that had been filed with the Commission.[20] In response to a further document request seeking more specific documents, Duke responded with presentations to its Grid Modernization Oversight Committee that included quantified costs and benefits for certain smart grid technologies.[21] The costs and benefits contained in these presentations were not included in the filed SGT plans, nor was any underlying analysis. NCSEA and EDF believe that if these quantified costs and benefits are based on underlying formal cost-benefit analyses performed by Duke, the underlying analyses should have been included in the filed SGT plans. NCSEA and EDF also believe that, in the alternative, if these quantified costs and

[20] *See generally*, **Exhibit K** (*NCSEA DEC DR1, Item No. 1-7*, Commission Docket No. E-100, Sub 141); **Exhibit L** (*NCSEA DEP DR1, Item No. 1-7*, Commission Docket No. E-100, Sub 141).

[21] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

benefits are based on rough calculations, the quantified costs and benefits as they appeared in the internal presentations should have been included in the filed SGT plans.

As originally approved by the Commission, Rule R8-60.1 required the utilities to file their SGT plans by 1 July 2013, and biennially thereafter.[22] However, the utilities petitioned the Commission to amend the rule to require the plans be filed by 1 October 2014, and biennially thereafter.[23] One of the reasons cited by the utilities in requesting a change in the filing deadline for the initial SGT plans from 1 July 2013 to 1 October 2014 was because "developing the SGT Plan for an odd-year July 1 filing date that does not correspond with the Utilities' even-year IRP requirement may mean that the Utilities will not be able to incorporate the analysis from that year's planned September 1 IRP update and, therefore, may have to rely upon results from the prior year's IRP, which may be nearly 10 months old."[24] Despite the utilities assertion that "there is substantial value in using [the utilities'] most current IRP analyses to develop future SGT Plans[,]" and the Commission granting the utilities fifteen extra months to compile their SGT plans, the SGT plans filed by the utilities fail to comply with Rule R8-60.1 because they contain little to no analysis, much less any analysis that builds on, or is even comparable to, the analysis included in the IRPs filed in this docket.[25]

North Carolina is not the only state where utilities have filed long-term plans for the implementation of smart grid technologies. In a case before the Indiana Utility

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22 *Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1*, Appendix A, p. 2, Commission Docket No. E-100, Sub 126 (11 April 2012).
23 *See generally, Dominion NC Power, Duke and PEC's Joint Motion to Amend Rule R8-60.1(b)*, Commission Docket No. E-100, Sub 126 (10 April 2013).
24 *Id.*, p. 3.
25 *Id. See generally, Order Amending Rule R8-60.1*, Commission Docket No. E-100, Sub 126 (6 May 2013).

Regulatory Commission, Duke Energy Indiana provided much greater detail about its plans for the deployment of smart grid technologies. The filing provided detailed information for numerous smart grid technologies related to budget, timeframe, project description, current state, desired state, benefits to customers, reliability, operation, and integrity, and risks of not doing the project.[26] A cost-benefit analysis performed by Duke Energy Ohio and submitted to the Public Utilities Commission of Ohio estimated the net present value of cumulative savings due to the implementation of smart grid technologies to be $294.35 million after twenty years.[27]

In 2013, a Duke Energy executive identified $238 million in savings due to smart grid and distributed automation projects in all service areas.[28] If Duke Energy has calculated these savings for all its subsidiaries, DEC and DEP should be capable of calculating these savings and including them in their SGT plans. Duke included no cost-benefit analyses in its filed SGT plans, despite describing how Duke Energy's Emerging Technology Office provides benefits to Duke's customers in North Carolina.[29] Additionally, in its filed SGT plans, Duke goes to great detail to explain the internal corporate development process for new technologies, including several stages in the process where costs and benefits are assessed, but fails to explain these assessments in detail or provide the quantitative analysis.[30] If Duke is evaluating the costs and benefits of

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[26] *See generally*, **Exhibit C**.
[27] **Exhibit D**, p. 38.
[28] Mark Wyatt, Duke Energy Grid Modernization Update, presented at IEEE PES Conference, p. 12 (26 February 2013), http://sites.ieee.org/isgt/files/2013/03/Wyatt.pdf.
[29] *DEC 2014 SGT Plan*, *supra* note 4, p. 8; *DEP 2014 SGT Plan*, *supra* note 5, p. 8.
[30] *DEC 2014 SGT Plan*, *supra* note 4, pp.12-20; *DEP 2014 SGT Plan*, *supra* note 5, pp. 12-20.

technologies at all these various points and stages in its internal corporate development process, it is clearly capable of providing these cost-benefit analyses in its SGT plans.

The utilities' failure to provide cost-benefit analyses is all the more curious given the discussion of replacing aging transmission and distribution equipment and meters with smart grid technologies in their filed SGT plans.[31] By providing no description or cost-benefit analysis of these efforts, one could reasonably interpret Duke's filed SGT plans as meaning the utilities expect no transmission or distribution equipment at substations and field locations to require replacement over the next five-years and be replaced by newer, advanced SGT, as is the current practice.

IV. THE SGT PLANS FILED BY THE UTILITIES FAIL TO INCLUDE ADEQUATE TECHNOLOGY DESCRIPTIONS, AS REQUIRED BY RULE R8-60.1(c)(1).

In response to the directive concerning technology descriptions, Duke provides generalized information about certain smart grid technologies, such as distributed automation, advanced metering infrastructure ("AMI"), microgrids, and distributed energy generation, but not detailed descriptions of technologies.[32] DNCP also provides generalized information without detailed descriptions about AMI meters, improvements to

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[31] "[U]pgrades to transmission and distribution equipment at substations and field locations has been a continual process as part of normal operations and maintenance. For example, when substation devices are removed for failure or scheduled maintenance, they are often replaced with equipment that can be remotely monitored and controlled through SCADA systems. . . . In addition to DA, Duke Energy is also upgrading the metering infrastructure. The Company's proposed AMI solution will be a fully automated metering system that provides two-way communications between the meter and the back office data systems, and would be capable of performing remote operations of the meter, including remote meter reads, upgrades, and disconnections and reconnections, among other attributes." *DEC 2014 SGT Plan*, *supra* note 4, p. 22; *DEP 2014 SGT Plan*, *supra* note 5, p. 22.

[32] *DEC 2014 SGT Plan*, *supra* note 4, pp. 3-4, 10, 22-24, 26-28, & 35-36; *DEP 2014 SGT Plan*, *supra* note 5, pp. 3-4, 10, 22-24, & 26-28.

transmission operations, and its microgrid demonstration project.[33] However, the lack of detailed technological descriptions means the filed SGT plans fail to provide enough specific information to adequately inform the Commission and stakeholders about utility plans for implementing smart grid technologies.

Grid-wide improvements have the potential to reduce losses that occur before energy reaches end-users. Accordingly, information about grid-wide improvements is important to ensure that North Carolina's citizens are receiving all the benefits that smart grid technologies provide. However, only DEC discussed Integrated Volt-Var Control ("IVVC"), also referred to as Volt/VAR Optimization, in its filed SGT plan.[34] In its IRP, DEC noted that it expects deployment of IVVC to reduce future distribution-only peak needs by 1.0% in 2020 and beyond, but DEC did not include these projections in its filed SGT plan.[35] The lack of discussion about this technology in DEP's filed SGT plan is notable because DEP discussed the technology in its recent IRP.[36] In that filing, DEP estimated that the implementation of IVVC technology would save over 71,500 MWh in 2028.[37] Based on filed IRPs, it is clear that Duke believes IVVC will save energy. However, Duke's filed SGT Plans fail to provide any information about IVVC beyond that which is contained in the IRPs. In contrast, Duke Energy subsidiaries have provided sufficient information to regulatory agencies in other states to allow them to make educated decisions about what would be best for their ratepayers. For example, a cost-benefit

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[33] *DNCP 2014 SGT Plan, supra* note 6, pp. 1-3.
[34] *DEC 2014 SGT Plan, supra* note 4, p. 36.
[35] *DEC's 2014 IRP and REPS Compliance Plan*, p. 105, Commission Docket No. E-100, Sub 141 (2 September 2014).
[36] *DEP 2014 IRP (Redacted) and Testimony*, pp. 96-97, Commission Docket No. E-100, Sub 141 (2 September 2014).
[37] *Id.*, p. 97.

analysis performed by Duke Energy Indiana found that it would be cost-effective to invest approximately $122 million in IVVC over seven years because the technology would produce 2% in annual energy savings for customers.[38]

Nationwide, approximately 43% of residential customers have AMI meters.[39] In North Carolina, however, only 8.4% of the residential customers of the utilities have AMI meters.[40] This lack of deployment is not because the utilities are unfamiliar with the technologies. By 2015, Duke estimates it will have installed over 1,250,000 AMI meters nationwide, while DEC has installed approximately 325,000 AMI meters and DEP has installed approximately 54,706 AMI meters in their respective North Carolina service areas.[41] Dominion has installed approximately 260,000 AMI meters in its Virginia service area, but none in its North Carolina service area.[42]

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[38] **Exhibit C**, pp. 10-11.

[39] *Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid*, p. 1, The Edison Foundation Institute for Electric Innovation (September 2014); *DEC 2014 SGT Plan*, *supra* note 4, p. 4; *DEP 2014 SGT Plan*, *supra* note 5, p. 4.

[40] The utilities have a total of 237,384 residential AMI meters installed: DEC has installed 182,678 residential AMI meters; DEP has installed 54,706; DNCP has none installed. **Exhibit E** (*NCSEA DEC DR1*, Item No. 1-2, Commission Docket No. E-100, Sub 141); **Exhibit F** (*NCSEA DEP DR2, Item No. 2-1*, Commission Docket No. E-100, Sub 141); *DNCP 2014 SGT Plan*, *supra* note 6, p. 4. The three utilities have a total of 2,816,458 residential accounts in North Carolina: DEC has 1,610,269; DEP has 1,104,867; DNCP has 101,322. *Application for Approval of REPS Cost Recovery Riders and 2013 REPS Compliance Report*, Byrd Exhibit No. 1, p. 4, Commission Docket No. E-7, Sub 1052 (5 March 2014); *Duke Energy Progress, Inc.'s Direct Testimony and Redacted Exhibits of Byrd and Williams*, Duke Energy Progress 2013 REPS Compliance Report, p. 5, Commission Docket No. E-2, Sub 1043 (23 June 2014); *Application for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance*, p. 4, Commission Docket No. E-22, Sub 514 (28 August 2014).

[41] Grid Modernization FAQs, Duke Energy Corporation, http://www.duke-energy.com/about-us/smart-grid-faq.asp; *DEC 2014 SGT Plan*, *supra* note 4, p. 4; **Exhibit F**.

[42] *DNCP 2014 SGT Plan*, *supra* note 6, p. 1.

AMI meters allow customers to participate in time-based pricing, which can range from TOU pricing to dynamic pricing. TOU pricing sets predetermined rates based on operating costs for periods of time during the day that are determined to be on-peak and off-peak based on overall system demand. In contrast, rates for dynamic pricing, which includes critical peak pricing and real-time pricing, are determined by real-time, or close to real-time, changes in marginal costs that vary with supply and demand.[43] When a customer choses to be billed using time-based pricing, the utilities will typically install an AMI meter to allow for the necessary data to be captured to allow for the billing structure. Providing a variety of time-based pricing options for customers can create equality in electricity pricing, increase customer awareness of their energy use, and promote alternative control options to manage energy consumption.[44] Despite these benefits,

[43] A utility's marginal costs are the added costs of increasing electricity generation by one unit from different sources of electricity generation, i.e. conventional resources and clean energy resources.

[44] One time-based pricing option is for a utility to notify customers in advance of peak periods of energy demand. The Commission has previously noted that smart grid technologies will increase the opportunity for the utilities to provide such advance notice and has recommended and strongly encouraged the utilities pursue opportunities for notifying customers in advance of periods of peak energy demand. *Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice*, p. 23, Commission Docket No. E-7, Sub 1031 (29 October 2013); *Report of the NCUC to the Governor, Environmental Review Com. & Joint Legislative Utility Review Com.*, p. 48, Commission Docket No. E-100, Sub 116 (2 September 2008); *Order Denying Rulemaking Petition*, pp. 10-11, Commission Docket No. E-100, Sub 133 (30 October 2012). NCSEA has previously encouraged the Commission to require the utilities address how they will provide customers with notice of forecasted periods of peak demand. *See generally*, *NCSEA's Post-Hearing Brief*, pp. 14-17, Commission Docket No. E-7, Sub 1026 (19 August 2013); *NCSEA's Filing Instead of Post-Hearing Brief*, pp. 7-10, Commission Docket No. E-2, Sub 1030 (17 October 2013). In considering these issues, the Commission wrote that it "encourages DEC, NCSEA, and other interested parties to comment on the advance notice of peak usage possibilities in the smart grid technology proceeding." *Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice*, p. 23, Commission Docket No. E-7, Sub 1031 (29 October 2013). In its filed SGT plan, DEC noted that "there is a draft pilot rider being evaluated to provide customers with a peak

however, adoption of TOU rates has been extremely limited in North Carolina. DEC currently has only 2,340 residential TOU customers in the State.[45] DEP's residential customer participation in TOU rates has declined over the years, from approximately 27,000 customers in 2006 to 26,000 customers in 2012 to 25,387 currently.[46] DNCP has a mere 312 residential TOU customers in North Carolina.[47]

RELIEF REQUESTED

NCSEA and EDF submit that the SGT plans filed by the utilities fail to provide sufficient detail to comply with Rule R8-60.1, and therefore fail to provide enough information to allow the Commission and stakeholders to determine whether the utilities have thoroughly developed their SGT plans. Because of these deficiencies, NCSEA and EDF request that the Commission require the utilities file supplemental information in this docket to fully comply with Rule R8-60.1, and require such information be included in all future SGT plans filed in accordance with the rule.[48] NCSEA and EDF recognize that it

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time rebate during Company-designated peak load periods, known as Critical Peak Events[,]" referring to DEC's proposed pilot Peak Time Credit Program. *DEC 2014 SGT Plan, supra* note 4, p. 43; *see generally, DEC's Proposed Pilot Peak Time Credit Program*, Commission Docket No. E-7, Sub 1026 (7 November 2014). However, neither DEP nor DNCP discuss notifying customers prior to periods of peak energy demand.

[45] **Exhibit G** (*NCSEA DEC DR1, Item No. 1-21*, Commission Docket No. E-100, Sub 141). Curiously, DEC stated that it has only deployed 1,266 residential TOU meters. **Exhibit E**.

[46] *Post Hearing Brief of NCSEA*, p. 14, Commission Docket No. E-2, Sub 1023 (29 April 2013); **Exhibit H** (*NCSEA DEP DR1, Item No. 1-21*, Commission Docket No. E-100, Sub 141).

[47] **Exhibit J**.

[48] NCSEA and EDF also request the Commission require the utilities include in their SGT plans information about projects that were considered but ultimately cancelled and the rationale for the cancellation. Such a requirement would be consistent with Commission expectations for the contents of other mid- and long-term planning filings. For example, in the development of the current version of the rule governing IRP filings, the Commission stated that it "expects the utilities' IRP filings...to fully consider DSM and EE options and to explain the reasons that a utility chose to either include or decline to include specific

may not be efficient to require the utilities to rewrite their SGT plans from scratch to include additional information to address the deficiencies noted in these comments. Therefore, NCSEA and EDF request that the Commission decline to issue an order accepting the SGT plans filed by the utilities until additional information has been provided by the utilities to address deficiencies through either reply comments or in a supplemental filings. Furthermore, NCSEA and EDF request that the Commission require this supplemental information include a cost-benefit analysis for full smart grid deployment by each utility throughout its territory. Duke Energy has already performed such analyses in Indiana and Ohio. A cost-benefit analysis for full smart grid deployment is the best way for the Commission to determine whether the utilities' SGT plans are reasonable.

Alternatively, Rule R8-60.1(d) gives the Commission the discretion to hold a hearing to address issues raised by the Public Staff or other intervenors. Given that the utilities have filed their initial SGT plans pursuant to Rule R8-60.1 and NCSEA and EDF have raised significant issues regarding the SGT plans filed by the utilities, should the Commission decline to require the utilities file supplemental information, NCSEA and EDF request the Commission hold such a hearing.[49] A hearing would allow the Public Staff and intervenors to provide expert testimony and information about the level, amount, and type of content that should be included in the utilities' SGT plans, and would therefore allow the Commissioners to determine whether the SGT plans filed by the utilities

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programs in its resource plans." *Order Adopting Final Rules*, p. 85, Commission Docket No. E-100, Sub 113 (29 February 2008).

[49] NCSEA and EDF request a hearing only for the initial SGT plans filed by the utilities. NCSEA and EDF believe that if a hearing is held to address the deficiencies in the initial SGT plans, future SGT plans filed by the utilities should become routine and require few, if any, subsequent hearings.

adequately present information about the implementation of smart grid technologies by the utilities.

Finally, NCSEA and EDF urge the Commission to view this as an appropriate time to open a rulemaking docket to adopt clear data access policies for the State. NCSEA previously advocated that the Commission open a rulemaking docket on this issue and Duke has stated that it would not object to such a proceeding.[50] At that time, the Commission declined to initiate rulemaking, stating "it will be a more efficient use of time and resources to utilize the information provided in the IOUs' SGT plans to assist in determining whether a rulemaking is needed and, if so, the parameters of any proposed new rules."[51] The utilities have now filed their initial SGT plans, and the plans are deficient in addressing the accessibility of customer usage information. Accordingly, NCSEA and EDF request the Commission revisit the issue and initiate rulemaking on the issue of data access. For smart grid technologies to be of the most benefit to customers, data access policies need to be well-defined, enable ease of process, and provide granularity of data.

NCSEA and EDF note that the adoption of clear data access policies at this time will benefit customers even if smart grid technologies are installed gradually over a longer period of time. For example, "Green Button Connect is time-interval agnostic. Whether the utility billing interval is monthly, hourly, 15-minute or 5-minute, all time resolutions

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[50] *See generally*, *NCSEA's Comments*, p. 16, Commission Docket No. E-100, Sub 137 (5 February 2013); *Order Requesting Additional Information and Declining to Initiate Rulemaking*, p. 5, Commission Docket No. E-100, Sub 137 (23 August 2013) ("Duke states that it has engaged in a dialogue with NCSEA and the Public Staff about NCSEA's concerns regarding access to customer data and would not object to a Commission rulemaking proceeding on the subject").

[51] *Order Requesting Additional Information and Declining to Initiate Rulemaking*, p. 12, Commission Docket No. E-100, Sub 137 (23 August 2013).

(and all customer classes – residential, commercial, industrial) are supported by the Green Button Connect standard, making it truly universal."[52] By adopting clear data access policies at this time, the Commission can ensure that customers receive the economic benefits associated with having access to their energy consumption data, regardless of whether they have an AMR meter or an AMI meter.

NCSEA and EDF recognize that the Commission will have to confront and resolve the need to facilitate access to energy usage data while safeguarding customer privacy. The Commission can achieve this by establishing well-defined data access policies that provide access to energy usage data for awareness and control purposes, while protecting sensitive information about customers and their utility services.

Ease of process can be created by allowing customers to utilize electronic consent forms, non-disclosure agreements, or information transfer agreements. NCSEA has previously noted there is no standardization between the utilities in the forms used by customers to authorize the utilities release their data to a third party, nor a standard method of access to or submission of these forms.[53] The Commission recognized that the utilities

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[52] **Exhibit B**, p. 10.

[53] *NCSEA's Corrected IRP Comments*, pp. 25-26, Commission Docket No. E-100, Sub 137 (16 May 2014). At that time, NCSEA also noted at that time that the form used by Duke authorized only a single release of data to a third party, while the form used by DNCP authorized an ongoing release of information for a specified period of time. *Id.*, p. 25. NCSEA and EDF request that in rulemaking the Commission adopt DNCP's more reasonable approach. At that time, NCSEA also noted that forms did not appear to be available online for any of the utilities. *Id.*, pp. 25-26. In response, Duke stated that "DEC and DEP do have an online 'Energy Data Request Form,' for independent third parties with a need to use customer data." *DEC and DEP's Reply Comments*, p. 18, Commission Docket No. E-100, Sub 137 (23 May 2014). Informally, Duke also provided NCSEA with the address of a website where third parties could request customer data. Energy Data Request Form, available at https://www.signup4.net/Public/ap.aspx?EID=ENER111E. While available online, the website is not easily accessible from Duke's website. Further, it does not appear there is an electronic form on Duke's website for customers to authorize

"may be able to more readily facilitate the authorization for such sharing by creating a standard authorization form[,]" but the utilities have not done so.[54] NCSEA has also previously noted that the forms used by Duke for a customer to authorize the utility to release data to a third party describe a fee that must be paid by a third party requesting customer information.[55] At that time, NCSEA stated that the issue was more appropriately addressed in the smart grid planning process, and NCSEA and EDF now raise the issue and request the Commission address whether it is appropriate for the utilities to charge a fee for access to information that belongs to a customer.[56] NCSEA and EDF note that fees charged for access to data by third parties were not addressed in any of the filed SGT plans. The Commission can create ease of process by requiring the utilities standardize their authorization forms and make the forms accessible and able to be submitted online.

Awareness and control of energy consumption can be optimized if data access policies ensure granular time-based data is accessible. This data is key to the utilities and third parties providing energy management services to the customer. Many services and products, such as an EMS and time-based pricing, are obsolete without energy usage data. Granularity of data can be dictated by the Commission based on available and installed technologies. Transparency can be created by adopting carefully crafted policies giving customers control over their data.

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the release their data to third parties. NCSEA and EDF request that in rulemaking the Commission make such forms available the utilities' websites, easily accessible, and in a form that can be submitted to the utility with an electronic signature.

[54] *Order Requesting Additional Information and Declining to Initiate Rulemaking*, p. 10, Commission Docket No. E-100, Sub 137 (23 August 2013).

[55] *See generally*, *NCSEA's Corrected IRP Comments*, p. 25, footnote 14, Commission Docket No. E-100, Sub 137 (16 May 2014).

[56] *Id.*

CONCLUSION

As discussed in detail above, NCSEA and EDF believe that the filed SGT plans fail to comply with Rule R8-60.1. Accordingly, NCSEA and EDF request that the Commission decline to issue an order accepting the filed SGT plans until supplemental information has been provided by the utilities. Should the Commission decline to require the utilities file supplemental information, NCSEA and EDF request the Commission hold a hearing as authorized by Rule R8-60.1(d). Finally, NCSEA and EDF request the Commission initiate rulemaking on the issue of data access.

Respectfully submitted, this the 9th day of January, 2015.

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Peter Ledford

From: Greg Andeck
Sent: Friday, January 9, 2015 8:21 AM
To: John Finnigan
Cc: Ledford, Peter; Kacey Hoover
Subject: Re: Draft for this afternoon's meeting

Yes looks great. Good to go. Thanks.

Sent from my iPhone

On Jan 9, 2015, at 8:00 AM, John Finnigan <jfinnigan@edf.org> wrote:

> Peter – this looks great! I don't have any further comments. If Greg is ok with it, then you have authority to sign the document on behalf of me and Dan Whittle.
>
> **From:** Ledford, Peter [mailto:peter@energync.org]
> **Sent:** Thursday, January 08, 2015 12:10 PM
> **To:** Greg Andeck; John Finnigan
> **Cc:** Kacey Hoover
> **Subject:** Draft for this afternoon's meeting
>
> Greg and John,
>
> Attached is an updated draft of the comments based on feedback from Michael so that you are armed with the most recent version before this afternoon's meeting with the Public Staff. Greg, I'll bring physical copies to the meeting.
>
> Thanks,
>
> Peter
>
> --
> Peter H. Ledford
> Regulatory Counsel
> NC Sustainable Energy Association
> 4800 Six Forks Road, Suite 300
> Raleigh, NC 27609
> 919-832-7601 ext. 107
> peter@energync.org

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Comments by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 9th day of January, 2015.

Peter H. Ledford
Regulatory Counsel for NCSEA
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EXHIBIT A

plotwatt®

January 9, 2015

Chairman Edward S. Finley, Jr.
Commissioner Don M. Bailey
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner Susan Warren Rabon
Commissioner James G. Patterson
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603

RE: Smart Grid Technology Plans filed by Duke Energy Carolinas, Duke Energy Progress, and Dominion North Carolina Power
(Docket No. E-100, Sub 141)

Dear Honorable Commissioners,

My name is Luke Fishback. I am the CEO of PlotWatt, Inc. PlotWatt is an energy analytics company headquartered in Durham, NC, serving residential, commercial and utility customers. We currently employ approximately 25 full time employees, most of whom are engineers. PlotWatt has been awarded more than $10 million in prizes, grants, and equity funding, including selection as one of five global GE Ecomagination winners, honors from the White House, and a grant from the North Carolina Green Business Fund.

I have reviewed the Smart Grid Technology Plans filed by Duke Energy Carolinas, Duke Energy Progress, and Dominion North Carolina Power in Docket No. E-100, Sub 141. In their Smart Grid Technology Plans, Duke Energy Carolinas and Duke Energy Progress state that "No third-parties currently utilize any of the planned technologies[.]"

I am writing to make clear that third-parties do utilize the technologies that Duke Energy Carolinas and Duke Energy Progress plan to implement. Specifically, PlotWatt utilizes data and information from the utility's Advanced Metering Infrastructure ("AMI") meters to assist consumers in saving money. Data and information allows PlotWatt to deliver much-needed energy savings tools to consumers, including our patent-pending energy disaggregation service which enables homes and businesses to learn about their appliance-level energy usage and opportunities for savings. Our technology is currently installed in thousands of homes and small businesses around the world, saving our customers and average of 10-15% on energy bills. In service territories where utilities provide third-parties with access to meter-level data and information upon authorization by the consumer, PlotWatt is already delivering invaluable insight on energy consumption. In North Carolina, however, the lack of access to meter-level data necessitates consumers installing a secondary device to measure energy consumption to provide PlotWatt with the data and information necessary to perform our analytical services.

I know the Commission is extremely busy, but PlotWatt believes that the statement of Duke Energy Carolinas and Duke Energy Progress that "No third-parties currently utilize any of the planned technologies[]" is incorrect.

Respectfully submitted,

Lucas Fishback
Chief Executive Officer and Founder
PlotWatt, Inc.
luke@plotwatt.com

EXHIBIT B

MISSION
empowering energy savings

January 9, 2015

Chairman Edward S. Finley, Jr.
Commissioner Don M. Bailey
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner Susan Warren Rabon
Commissioner James G. Patterson

North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603

RE: **Docket No. E-100, Sub 141**
Commission Rule R8-60.1, Smart Grid Technology Plan

Dear Members of the North Carolina Utilities Commission:

Mission:data is a national coalition of technology companies delivering consumer-focused energy savings for homes and businesses. We represent a strong, vibrant ecosystem of innovative technology companies – with sales in excess of $600 million per year – who have developed many products leveraging smart meter data to benefit consumers and utilities. We write to provide our informal feedback on the Smart Grid Technology plans filed October 1, 2014, by the investor-owned utilities serving North Carolina, including Dominion North Carolina Power, Duke Energy Carolinas and Duke Energy Progress.[1]

Energy efficiency represents an enormous economic opportunity. Approximately 40 percent of the nation's energy use is in buildings.[2] Approximately 20 percent of this amount represents waste that can be eliminated.[3] More than ever, the plummeting cost of computing power is giving consumers unprecedented low-cost opportunities to effectively manage individual energy use decisions and achieve energy savings – significant not only to each individual household and business but also in the aggregate.[4]

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[1] *Duke Progress 2014 Smart Grid Deployment Plan*, October 1, 2014; *Duke Carolinas 2014 Smart Grid Deployment Plan*, October 1, 2014; *Virginia Electric and Power Company d/b/a Dominion North Carolina Power's Smart Grid Technology Plan*, October 1, 2014.

[2] U.S. Department of Energy, see http://www.eia.gov/tools/faqs/faq.cfm?id=86&t=1

[3] See Armel, K. Carrie, et. al. *Is Disaggregation the Holy Grail of Energy Efficiency? The Case of Electricity*, Technical Paper Series: PTP-2012-05-1, Precourt Energy Efficiency Center, Stanford University, 2012, p. 3

[4] Mission:data would highlight studies such as those by the Institute for Electrical Efficiency (Edison Foundation) showing that Advanced Metering Infrastructure can achieve both significant operational savings for utilities and consumer savings enabled by better energy management. See Institute for Electrical Efficiency, *The Costs and*

Utilities have always collected energy usage information for billing purposes. Providing customers access to their own energy information in an automated format is now enabling consumers in several states to access innovative, low-cost technology tools that can save them energy and money. Examples include (1) "no-touch" energy audits; (2) device-specific recommendations to reduce energy use, (3) tools to manage load and reduce costs (3) recommendations for and sizing of solar, other renewable and clean energy installations and (4) frictionless verification of efficiency or demand response curtailments.

Mission:data therefore supports providing consumers convenient, electronic access to the best available information about their own electricity use. Specifically, we support two low-cost strategies, providing consumers access to

(1) their own electricity usage and pricing information through interval data provided via the utility's website in standardized formats, and

(2) their smart meter real-time usage data through enablement of the Home/Business Area Network (HAN/BAN) radio contained within the 383,000 smart meters deployed in the Carolinas, where that technical capability exists.[5]

With the percentage of North Carolina household income spent on residential electricity bills approximately 75 percent higher than in states like California[6], Mission:data is eager to work with the Commission, utilities, and other stakeholders to help North Carolina consumers save energy and money.

While the utilities' plans offer positive recognition of the role that smart grid technologies can play, Mission:data believes that these plans can and must be strengthened to provide consumers access to their own energy data and full access to new tools to save energy and money. Mission:data is puzzled by the statement in the Duke Energy plans that "No third-parties currently utilize any of the planned technologies, nor is customer information shared with any third-parties."[7] If this statement implies that third-parties implementing

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Benefits of Smart Meters for Residential Customers, July 2011. See also the California Public Utilities Commission, Resolution E-4527, referencing the application of Southern California Edison for approval of its AMI deployments, an application that cited approximately $1.1 billion in operational benefits and more than $800 million in consumer, demand-side reduction benefits.

[5] *Duke Energy Carolinas 2014 Smart Grid Technology Plan*; October 1, 2014, p.4. and *Duke Energy Progress, 2014 Smart Grid Technology Plan*, October 1, 2014; p. 4. These reports indicate that DEC has installed 325,000 smart meters and DEP has installed 58,000 smart meters in their service territories of North Carolina and South Carolina, although the breakdown within each state is not specified.

[6] This calculation is based on Energy Information Administration, U.S. Department of Energy, 2012 comparisons of monthly residential electricity bills by state http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf divided by household income as found at http://www.census.gov/quickfacts/table/INC110213/06,48,37,00. Calculations using these sources suggest that residential electricity bills consumer about 3% of the average household income in North Carolina, compared to about 1.7% in California.

[7] See *Duke Energy Carolinas 2014 Smart Grid Technology Plan*; October 1, 2014, p.42. and *Duke Energy Progress, 2014 Smart Grid Technology Plan*, October 1, 2014; p. 38.

data-driven software solutions do not exist, Mission:data feels compelled to correct the misimpression. Furthermore, it appears that Duke Energy replied to the question as though it were about the current status of third parties' access to usage data, and not on a forward-looking basis, after the proposed smart grid technologies are implemented. We can assure the Commission that our members will be ready to assist North Carolina consumers to save energy and money once the utilities enable access to data in the two methods described above.

In addition to addressing the needs of its consumers, North Carolina -- with technology leaders like Plotwatt headquartered in the state -- also has significant potential to the lead the development of consumer-oriented energy management technologies. In general, Mission:data urges the Commission to enable prompt customer access to energy data and support for the deployment of cost effective technologies that advance both consumer interests and the state's technology leadership.

1. **Empowering residential and commercial customers with access to their electricity data can deliver significant energy and cost savings.**

In general, Mission:data agrees with Dominion's summary of the potential of smart grid technologies to deliver direct, tangible energy-saving and bill-reducing benefits for consumers, including:

> "• Improving operational efficiency and energy efficiency through AMI-enabled energy conservation, lessening the need for off-system power purchases which are passed on to all customers in rates;
> • Supporting greater customer choice and control by offering feedback tools that provide timely information to customers about their electricity consumption; and
> • Helping to modernize the electric grid by creating a foundation for the support of new uses of electricity such as electric vehicles, distributed generation, and other distributed energy resources."[8]

Where energy usage and cost data delivered to consumers, the energy and cost savings are significant. For example, the American Council for an Energy Efficiency Economy (ACEEE) found that peer-reviewed research showed a 4% to 12% energy savings among consumers exposed to feedback on their consumption,[9] with real-time data and feedback mechanisms enabling the highest energy savings.

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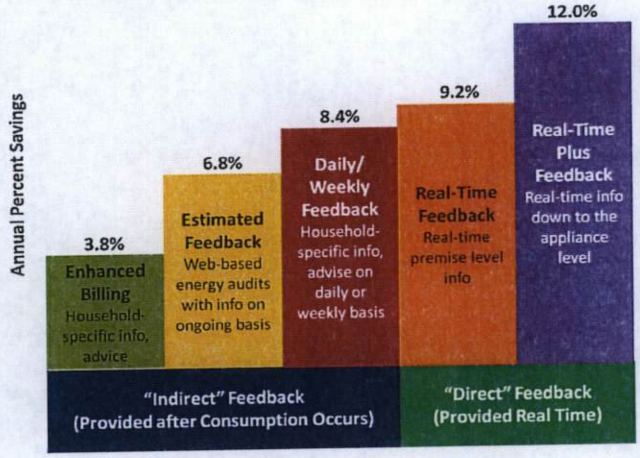
[8] *Virginia Electric and Power Company d/b/a Dominion North Carolina Power's Smart Grid Technology Plan*, October 1, 2014, p. 2

[9] ACEEE. "*Advanced metering initiatives and residential feedback programs: a meta-review for household savings opportunities.*" Karen Ehrhardt-Martinez, Kat Donnelly, John Laitner. June 2010. Report number E105. It is important to note that adoption of energy efficiency measures is not uniform across large numbers of households. Some people achieve savings well in excess of these amounts and others achieve less. At least initially, we would expect that aggregate savings across large numbers of households would be approximately half of these amounts.

Average Household Electricity Savings (4-12%) by Feedback Type



Based on 36 studies implemented between 1995-2010

The table above provides a numeric range of achievable energy savings in homes enabled by varying types of data in conjunction with technology tools.[10]

Other studies buttress these results. A 2012 study of real-time information feedback approaches, in which consumers could react to instant power usage readings by reducing lighting or appliance loads, found energy savings on average of 3.8% across large populations; most encouraging was that some households saved over 25%.[11] Recent studies involving BC Hydro's use of rebates to spur residential use of Rainforest Automation's HAN devices have found average residential savings of 6% - 9% and significant consumer satisfaction, even though electricity costs as low as $0.07 per kilowatt-hour in that region would appear to create weak incentives for conservation.[12]

Bidgely's energy services use real-time data to achieve 6% savings across large populations, leveraging a combination of real-time data and cloud-based disaggregation strategies. In a study with a retail electricity provider operating in competitive markets, Bidgely reported very high levels of customer engagement and satisfaction with its energy-saving tool.[13] Similarly, a 2013 study of more than 5,000 NV Energy customers in southern Nevada using EcoFactor thermostats found savings of almost $100 per month in electricity costs, together with significant demand response in more than 20 events.[14]

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[10] These results should be viewed in the context of when this study was published (2010). Over time we expect savings to increase as technologies improve.

[11] ACEEE. "*Results from recent real-time feedback studies.*" Ben Foster and Susan Mazur-Stommen. February, 2012. Report number B122.

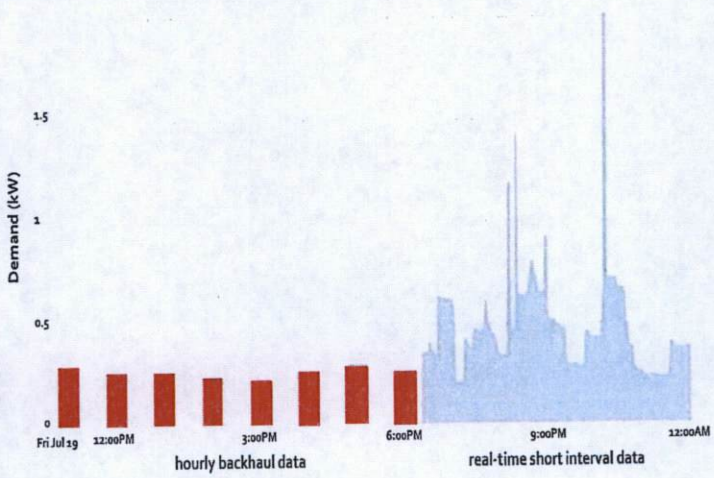
[12] http://www.bchydro.com/powersmart/residential/smart_meters___conservation/monitors.html?WT.mc_id=rd_energymonitor and http://rainforestautomation.com/blog/real-time-energy-usage-launched-bc-hydro-customers/

[13] http://bidgely.com/resource-files/Case_Study-Demand_Management.pdf and http://bidgely.com/resource-files/Case_Study-Customer_Engagement.pdf

[14] ADM Research and Evaluation, *Demand Response Program NV Energy – Southern Nevada (NPC) Program Year 2013, Final Evaluation Report* (prepared for NV Energy), June 4, 2014

With regard to interval data used in commercial and industrial sectors, Lawrence Berkeley National Laboratory has found median savings of 17% from individual energy information systems (EIS) that analyze interval usage data.[15] A Natural Resources Defense Council (NRDC) study found 13.2% energy savings in commercial buildings with an EIS.[16] Many other studies document the benefits of monitoring-based commissioning, which depends entirely on electronic access to interval usage data. One of the primary reasons that EISs and monitoring-based commissioning are not more prevalent in the marketplace today is that conventional methods of acquiring interval usage data for analysis are costly and labor-intensive. Typically, EISs today require installation of a redundant submeter on the customer's side of the utility meter to record usage in a useful and accessible format. Submeters, including related data-logging equipment and installation, can cost businesses between $3,000 and $6,000 each. The fact that some businesses are willing to pay these costs today demonstrates the tremendous value that EISs have in the commercial and industrial sectors.

It is worth differentiating between backhauled ***interval data*** typically made available through the utility web portal in 15-minute or hourly increments, on a 24-hour delayed basis; and highly-granular ***real-time data*** from the Home Area Network radio in a smart meter, which can provided by the meter in near real-time to an energy monitoring device owned by the consumer in increments as short as six seconds. The chart below depicts household usage graphed through each of these interfaces:



Both interfaces can enable enormous value for customers.

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[15] *Energy Information Systems (EIS): Technology Costs, Benefits, and Best Practice Uses*. Granderson, J., G. Lin. November 2013. LBNL-6476E.

[16] NRDC. "*Real-time energy management: A case study of three large commercial buildings in Washington, D.C.*" Philip Henderson and Meg Waltner. October 2013. Study number CS:13-07-A.

2. ***Customer access to backhauled interval data can enable a myriad of useful energy services.***

By "interval data" we refer to a customer's own energy data collected by the utility through the meter, backhauled through the utility infrastructure and provided on the utility website to the customer third parties authorized by the customer. Time-series consumption data available either at a monthly level or so-called "interval data" (i.e., 5-minute, 15-minute or hourly intervals, typically with a time lag) are both valuable in different ways. Even where AMI is not deployed, Mission:data believes customers should have access to their own, best-available data, i.e., the most granular usage data that is available[17]. In regions with advanced metering, interval data is important for applications including, but not limited to, the following:

- Virtual or "no touch" energy audits that identify efficiency opportunities such as poor building scheduling, high air infiltration, HVAC equipment problems, etc.;
- Peak load management (for example, predicting when a peak is going to occur, and proactively notifying the homeowner or business via email or text message);
- Measurement and verification of energy savings from efficiency programs, or peak load reductions for participation in demand response programs;
- Generating, instantly and with software, an accurate cost-savings estimate of solar photovoltaic installations, taking into account time-of-use rates, as opposed to using state-wide average electricity rates

Where it is collected with older metering technologies and provided on a monthly basis, customer usage data, in both a residential and commercial/industrial context, is useful for services such as:

- EnergyStar benchmarking, by making it easier to voluntarily benchmark commercial buildings and pursue efficiency measures;
- For landlords to communicate to prospective tenants annual utility usage and costs in homes, apartments or commercial buildings for rent, so that tenants can take that into account in their rental decisions;
- Degree-day analysis (i.e., understanding the magnitude of temperature impacts on energy use);
- Bill analysis, to flag outliers for further investigation;
- Cost management, for businesses or homeowners to actively manage energy use, rather than passively treat it as a fixed cost;

[17] For states like North Carolina with broad AMR deployments, it is worth noting that there are some AMR gateway devices available on the market for $100 or less that, depending on the exact AMR technology deployed, can provide customers with access to interval data. Despite limitations, this opportunity is worth exploring in cases where AMR will not reach the end of its useful life for some time. However, most states where Mission:data has engaged are focused on deriving value from new AMI investments because of AMI's substantial advantages relative to older technologies.

- Prioritizing and sequencing efficiency pursuits, starting with the "worst energy offenders," for large apartment complex landlords or commercial building portfolio owners.

3. ***Where AMI is available, real-time data access can realize significant savings.***

By "real-time data," we refer to data transmitted from a HAN radio in the Smart Meter directly to a home area network device (e.g. a gateway) owned by the customer that can provide that data in a useable format to the customer, allowing the customer to see, understand and/or control his or her energy use in real time through smart phones, personal computers or other devices.

Real-time data is superior to delayed longer-interval data in terms of delivering value for consumers. Real-time data made available to customers in small increments – as little as 6 seconds in California and Texas -- enables disaggregation, the use of algorithms to interpret smart meter data to identify energy used in a household by *device*. Appliances have unique electricity usage "signatures" that allow algorithms using high-interval, real-time data to identify the device being used and its energy performance (e.g. whether it is an Energy Star refrigerator working well or an old clunker that needs to be replaced).

The figure above depicts these electronic signatures that can be obtained through analysis of whole-house electricity usage data from a smart meter. The knowledge of what devices are consuming, in turn, enables the development of automated personalized recommendations such as "Save $__ per month by reducing your pool pump run time by 30 minutes." or "Save $____ per year, by buying a new washer." Real time data, with feedback, also allows consumers to easily gain an instant understanding of the energy use of any device and enables more effective demand response should the consumer choose to participate in such a program.

As mentioned above, the savings enabled by technologies like disaggregation are substantial. In the commercial sector, Raleigh-based Plotwatt has emerged as a leader in disaggregation technology. Its software has enabled local franchising operations in the states to save up to $7,700 annually per restaurant, real savings that allow businesses to increase hiring and invest in growing their operations.

It is worth noting that privacy and security requirements have already been developed and are in effect in states like California and Texas. Typically real-time data transmitted to a consumer device is secured through Zigbee standard protocols (Smart Energy Profile 1.x or 2.0). California, for example, requires the use of reasonable security procedures.

We do not believe an individual consumer's right to access his or her own usage data raises significant privacy concerns. As to the privacy issues associated with sharing data with third parties, Mission:data believes that consumers should be educated up front about what data will be collected, how it will be used and how they can withdraw their authorization should they desire to do so. There are a number of rules or regulations in place that can serve as templates to address these issues. In any event rules applicable to emerging growth companies in this sector should be comparable to those in other sectors and should not be unduly burdensome or create undue advantages for one set of marketplace participants.

4. **Customer data should be provided in an electronic format, convenient for consumers to use and based on industry-led, widely adopted standards.**

The key value of data in a machine-readable format is that software (via PCs or cloud-based services accessed through tablets, smart phones or other consumer devices) can instantly parse and analyze it. This eliminates the friction involved in all manner of transactions, from evaluation, measurement and verification exercises; retrofit coordination among commissioning agents, contractors, energy services companies, and building owners; real estate transactions triggering benchmarking and disclosure; to price quotations from solar installers.

Energy usage in buildings depends upon a large number of individual decisions. If software can automatically be applied to these decisions, then transaction costs can be dramatically reduced; a much larger percentage of energy-use decisions can be cost-effectively managed to optimize energy use; and consumer confidence in the outcomes of efficiency projects or renewables installation will be increased, because they can easily be assessed. In short, software can lubricate all manner of efficiency transactions that are conducted today with manual work, data manipulations, spreadsheets emailed back and forth, scrutinizing paper bills, manual data entry exercises, etc. Software also enables information and insight to penetrate decision-making processes that are currently devoid of actual data.

A critical step toward providing data in an electronic format is the development of the industry-led "Green Button Connect" standard governing the utility's transfer of customer energy data via the utility website to the customer and authorized third parties.

Mission:data commends Dominion for joining more than 50 other utilities across the country in taking steps to empower its customers with basic energy data:

> "Dominion recognizes that some customers are interested in their energy usage information, which is available more frequently with AMI technology. Dominion has enhanced the energy information provided to customers to provide daily energy usage information. In addition, Dominion is a participating Green Button partner. The Green Button initiative provides customers the ability to access data related to their energy

use with a simple click of an on-line "Green Button." Green Button is a utility industry-led effort that allows electric customers to download their household or building energy-use data in a consumer- and computer-friendly format." [18]

There are two flavors of Green Button – Green Button Download, which requires a user to manually download their usage data and upload it to third-party applications, and Green Button Connect, which lets the user authorize a third party to have consistent access to that user's data. While Green Button Download is a useful first step, it has limited use because the customer must manually download the data stream each time a comparison is required.

Green Button Connect is much more powerful as an efficiency tool, as it is the only method that supports ongoing, automatic analysis of usage data without manual user intervention. As of early 2015, Green Button Connect is being implemented by Texas and California's investor-owned utilities as well as Pepco in Washington D.C. for commercial users. ComEd (Illinois) and PECO (Philadelphia) are engaging in pilots. In California, San Diego Gas & Electric implemented Green Button Connect before being required by the Commission with positive results: over 15 third parties registered, and thousands of customers have downloaded their usage data or shared it with third parties.

It is critical that data formats be provided in standards that are consistent across utility territories. In its plan, Duke makes an important point with which Mission:data agrees:

> "...Interoperability in grid devices is good for Duke Energy's customers and overall operations. When truly interoperable, field devices can share information based on location, saving time and decreasing response time compared to today's proprietary backhaul systems. Open and interoperable systems reduce utilities costs, which in turn reduce customer costs."

Mission:data agrees with this sentiment, not just with respect to utility-scale investments, but with respect to the enablement of customer data access through widely-adopted industry standards. We believe that all stakeholders' interests are served by data exchange platforms that strictly conform to nationally-recognized standards. Since many innovators come from across the country, it is important to reduce the barriers to their participation in the North Carolina market. Writing code for different states and different utilities because of non-standard electronic interfaces costs time and money. Balkanizing the data landscape into arbitrary service territories and geographies serves no one. Indeed, many innovative software developers simply will not enter the North Carolina market at all if data exchange protocols deviate from national norms.

For these reasons, with respect to interval data, we recommend that the Green Button Connect standard is the most appropriate for implementation in North Carolina. This standard provides data in an electronic format on an ongoing basis and in a format that is consistent across the states that are leading the effort to enable consumers. Also referred

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[18] *Virginia Electric and Power Company d/b/a Dominion North Carolina Power's Smart Grid Technology Plan*, October 1, 2014, p. 3

to as the Energy Services Provider Interface (ESPI), Green Button Connect was ratified as a standard by the ANSI-accredited North American Energy Standards Board (NAESB). The National Institutes of Standards and Technology (NIST) is the federal agency that coordinated the development of Green Button Connect beginning in 2009 among industry stakeholders including utilities, entrepreneurs, device manufacturers, etc. There is now a testing and certification process so that utilities can seek third party certification of their compliance with the standard. We strongly support regular, third-party testing and certification of utility Green Button Connect implementations so that technical consistency is assured while continuous improvements to the system are made.

Finally, it is important to note that Green Button Connect is time-interval agnostic. Whether the utility billing interval is monthly, hourly, 15-minute or 5-minute, all time resolutions (and all customer classes – residential, commercial, industrial) are supported by the Green Button Connect standard, making it truly universal.

With respect to enablement of the HAN radio, as previously discussed, we would point the Commission to the Smart Energy Profile (SEP) standards adopted for use by utilities in states like California and Texas.

Conclusion

In summary, Mission:data believes that consumers benefit from usage data in two forms: "backhauled" data via Green Button Connect, and through activation of the Home Area Network (HAN) radio, where deployed smart meters have such capability. It has been demonstrated that usage information can be effective in driving both energy savings and myriad energy management applications. While the above examples are illustrative, it is important to note that software innovation is continuous, and we expect many "killer apps" to be developed in the future, provided that customers across the nation can access their data electronically and in a standardized format.

If Mission:data can provide further help or clarification, please do not hesitate to contact us.

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MISSION
empowering energy savings

Mission:data members include:

Alarm.com

Alarm.com is an industry leading technology company that provides interactive security, video monitoring, energy management and home automation services through an intelligent platform and easy-to-use mobile apps. Access to data is important to be able to offer apps that can intelligently manage and control energy consumption in the home.

Bidgely

Bidgely is working to enable customers to save energy and utilities to meet their demand-side energy goals by disaggregating energy to itemize home energy usage data down to the appliance level without using any plug-level monitors. Energy data access helps Bidgely itemize how much energy each appliance uses. This allows households to identify sources of greatest inefficiencies and cost savings.

Blue Line Innovations

Blue Line Innovations has developed a very simple technology that passively acquires real time data from any electricity meter and then makes that available to the user in a number of different solutions from wireless monitors to cool smart phone apps to integrated Wi-Fi thermostats.

Bright Power

Bright Power helps building owners save energy, money and time by providing energy management and solar energy solutions. Specializing in multifamily residential buildings, Bright Power helps encourage waste reduction, improve cash flows, achieve energy law compliances and make building occupants more comfortable. Bright Power's EnergyScoreCards benchmarking software helps maximize energy efficiency, minimize cost to building occupants and owners make smart decisions and investments.

BuildingIQ

BuildingIQ provides a unique Software-as-a-Service solution to optimize energy use in commercial buildings. Using advanced algorithms to fine tune and control HVAC systems to reduce costs and peak loads while maintaining and improving building performance. The solution makes buildings HVAC systems smarter, more energy efficient and enables AutoDR without affecting tenant comfort.

The Cleanweb Initiative

The Cleanweb Initiative is a member-driven organization comprised of developers, entrepreneurs, investors and enterprises large and small who believe that the growing web of information technologies may be our most powerful tool to improving global sustainability, economic prosperity and human well-being. Data access is important to help drive smarter IT-based solutions and accelerate clean technologies to help spread sustainable behaviors.

EcoFactor

EcoFactor provides a cloud-based platform that analyzes data from various sources including connected thermostats, weather, consumer preferences, and unique home thermodynamics and applies customized algorithms to maximize savings to utilities, home service providers and energy retailers.

EnergyHub

EnergyHub is developing systems that reduce home energy consumption and save consumers money. They provide detailed energy usage information and support utility peak power reduction programs by delivering the next generation of energy management solutions to help the grid work smarter. Energy use data is important in accelerating utility demand response and energy efficiency programs.

EnerNOC

EnerNOC is a leading provider of energy intelligence software (EIS) and technology. Global enterprises use EnerNOC's applications to bring new clarity to how they buy energy, how much they consume, and when they use it to drive operational efficiency and improve productivity, while utilities and grid operators use EnerNOC's technology to enhance grid reliability and provide cost-effective alternatives to traditional power supply resources.

Genability

Genability enables New Energy Companies, such as solar developers, EV manufacturers and makers of Internet connected devices, to include smart energy into their products. Genability collects energy data, benchmark energy, and identifies cost savings to help build energy intelligence into different products and services.

Home Energy Analytics

Home Energy Analytics develops web-based customer engagement software employing advanced smart meter analysis to help residential energy consumers take control of their energy bills, and utilities & regulators to deploy cost-effective residential energy efficiency programs

iControl Networks

iControl Networks offers home management software solutions and enables service providers to deliver low-cost, high value services to customers. Data access is important to enable iControl to allow users to manage their home security, energy and healthcare activities.

Lucid

Lucid is revolutionizing buildings with software by providing real-time feedback on energy and water use. They developed a tool to manage and access all building performance energy data through a single interface. Data access through utilities will help customers eliminate the costs associated with redundant submetering.

Nest

Nest takes the unloved products in your home and make simple, beautiful, thoughtful things, including the Nest Learning Thermostat.

Open Utility

Open Utility is a London-based "internet of energy" company enabling electricity purchases directly from local suppliers. Support renewables not just on the grid, but from your neighbors.

People Power

People Power offers mobile and cloud technology solutions of connecting devices and analytics add-ins to be controlled by a mobile app. Their platform to power the Internet of Everything connects devices to People Power cloud services and allows customers to control them from anywhere.

Plotwatt

Using cloud-based algorithms, Plotwatt analyzes customer smart meter data to figure out appliance level energy costs without monitoring each individual appliance. Plotwatt provides appliance monitoring, savings, peak usages and rate optimization data to homes and restaurant businesses to help reduce energy bills.

Rainforest Automation

Rainforest Automation provides products that allow utilities and their customers to manage real time energy use. The wireless Home Area Network (HAN) product connects smart meter data systems to the cloud and allows, "plug and play" access.

Retroficiency

Retroficiency is fundamentally changing the way building efficiency is assessed by combining energy efficiency experience with software and data. Using analytics, Retroficiency is developing energy models for any type of building and allowing one to see how a specific building is consuming energy.

Solar City

Solar City provides solar energy for homeowners, businesses, school, non-profits and government organizations at lower costs than energy generated from fossil fuels. They provide full-service solar power system design, financing, installation and monitoring services.

Stem, Inc.

Stem delivers electricity bill savings to commercial and industrial customers through an integrated solution of cloud-based predictive software and advanced energy storage and provides utilities a low-cost, flexible, dispatchable power source to help them meet capacity challenges.

ThinkEco

ThinkEco is a green technology company creating cost-effective energy efficiency solutions. They developed the modlet, a self-installable solution that brings energy awareness and device-level energy management to home and office environments. In addition, they have developed a unique smartAC kit to control room AC and a platform for third party hardware integration.

Utilisave

Utilisave optimizes utility data so our clients pay less and use less.

Verdafero

Verdafero puts businesses' utility consumption information all in one place, providing unified utility management tools and services for some of the best-known companies and brands around the world, including Concord Hilton, Sugar Bowl Ski Resorts, the British Consulate-General, and Tech Credit Union.

WattzOn

WattzOn provides a personal energy management software platform that helps people save money and energy, helping users go from intent to action, with personalized recommendations and easy links to energy-smart purchases. With proven results nationwide and secure data connections to 160+ utilities, WattzOn's hardware-free platform is ready for turnkey private-label use and partnership integration opportunities.

More information about Mission:data is available at www.missiondata.org

EXHIBIT C

PETITIONER'S EXHIBIT B-1

Duke Energy Indiana T & D Infrastructure Improvement Plan

One-Page Summaries

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Distribution

Advanced Metering Infrastructure (AMI)

1st Year Budget: $26,710,000 **7 Year Budget:** $176,940,000

Expected Timeframe for Project Execution: 2015-2018

Project Description
Meter technology, the means by which meters can be interrogated, and the functionality which modern day meters offer have changed considerably over the past 20 years. This project involves upgrading all of the manually-read meters to an advanced metering infrastructure capable of two-way communications to enable operational efficiencies and enhanced customer service. This project includes the replacement of the electric meters, deployment of a communication network, expansion of the meter data collection system and meter data management system.

Current State
Manually reading meters and performing service turn ons/offs results in approximate annual O&M costs of $5.3 million and $6.7 million, respectively.

Desired State
Meter reading and customer order work such as service connects and service disconnects will be automated and worked remotely.

Benefits
Customer – More efficient outage restoration due to ability to ping meters to verify whether restoration efforts have been successful; quicker response for move ins and move outs through remote reads and service turn ons/offs; better usage data for customers to help them manage consumption; improved meter reading accuracy and reduced number of estimated bills.

Reliability – Enhanced ability to identify outage location due to ability to ping a subset of meters and confirm what customers have lost service, thus reducing outage duration.

Operational – Reduced labor hours, miles driven, and truck rolls.

Integrity – Improvements in the integrity of service to each customer by having a sensor at every meter with the ability to capture, timestamp, and record various parameters.

Risks of Not Doing Project
- Indiana could be at a disadvantage to other states when it comes to attracting economic growth and enhanced customer offerings through creative rates and/or programs enabled by advanced metering.
- Cost to manually read meters and to perform routine operations such as service turn ons/offs will continue to increase year after year due to labor inflation.

Distribution

Declared Circuits

1st Year Budget: $1,197,000 **7 Year Budget:** $16,594,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
A declared circuit is a poorly performing circuit that needs to be made as secure as possible from probable outage causes, especially sustained outage causes. The circuit is inspected from the substation to the first protective device. The inspection looks at all aspects of the construction and equipment. Examples could include connections, arresters, switches, jumpers, system grounds, any damaged equipment, and less-than-desired phase spacing.

Current State
This program is performed on an average of 15 declared circuits each year.

Desired State
Reduce the time to positively impact a large number of circuits gradually per year over the life of this program. During year 4, an estimated average of 30 circuits will be completed.

Benefits
Customer – Reduction of outages that affect large customer counts.

Reliability – Reduced risk of outages on main line circuits.

Operational – Reduced truck rolls 24/7.

Integrity – Proactive identification of deteriorated facilities.

Risks of Not Doing Project
- System reliability would continue to remain flat or possibly decline.
- Restoration O&M would remain flat or possibly increase by not reducing truck rolls.

Distribution

Deteriorated Conductor Replacement

1st Year Budget: $1,601,000 **7 Year Budget:** $12,346,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves replacement of small medium voltage conductors showing poor performance due to conditions, construction method, or age-related deterioration. Most of these conductors are copperweld or small Aluminum Conductor, Steel Reinforced (ACSR) with a small diameter that have a higher failure rate than larger conductors. Many times these conductors can be identified visually due to multiple splices that have been installed related to previous failures.

Current State

Approximately three deteriorated circuit conductor replacements are performed each year.

Desired State

Proactively identify and replace outdated conductor with signs of deterioration to reduce potential for failures and the need to replace on an emergency basis.

Benefits

Customer – Reduced outages.

Reliability – Reduced risk of outages.

Operational – Reduced emergency replacement or after-hours work; improved performance during extreme weather.

Integrity – Improvement of circuits and wire strength during extreme weather events.

Risks of Not Doing Project

- Increased customer outages.
- Decreased system reliability.
- Increased truck rolls.

Distribution

Distribution Automation (DA) – Distribution Line

1st Year Budget: \$10,416,000 **7 Year Budget:** \$78,879,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project encompasses distribution line current sensors, electronic recloser control replacements, self-healing teams, and circuit sectionalization. Line current sensors provide immediate outage detection, immediate permanent fault detection, and load monitoring. Electronic reclosers isolate faulted sections of distribution circuits and reduce the exposure of outages to customers. Self-healing teams use electronic-controlled reclosers, intelligent switches, and circuit breaker teams to locate and isolate portions of the distribution system affected by faults via automated switching and allow for supervisory-controlled switching capability for work activity. Sectionalization of distribution circuits reduces the exposure of customers to faults by adding and/or re-configuring a number of protective devices.

Current State
Only a small population of the distribution circuits have line current sensors. There are approximately 10 self-healing teams in Indiana, and no established cycle for sectionalization optimization. Existing electronic recloser controls lack remote communication and control.

Desired State
Increase the automation of distribution circuits by installing line current sensors, replacing all existing electronic recloser controllers with new microprocessor-based controllers that provide Supervisory Control and Data Acquisition (SCADA), adding approximately 15-20 self-healing teams, and adding rotating 5-year cycle for sectionalization of all circuits to improve overall reliability and rehabilitation of aging devices.

Benefits
Customer – Reduced interruption frequency and duration; reduced number of customers experiencing outages.

Reliability – Immediate outage detection; immediate permanent fault detection; reduction in customer sustained outage event by decreasing exposure; restoration of service to as many customers as possible while permanent repairs are made.

Operational – Improved circuit modeling; improved dispatch and fault location; improved operational intelligence through communication with protective devices.

Integrity – Proactive identification of potential failures on overloaded conductors/equipment.

Risks of Not Doing Project
- Less real-time telemetry resulting in decreased capability to locate and isolate a fault.
- Possibly flat or reduced reliability due to aging protective equipment remaining in service.

Distribution

Distribution Automation (DA) – Substation

1st Year Budget: $9,158,000 **7 Year Budget:** $67,329,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
The purpose of substation enhancement is to install newer, more reliable equipment and digital devices with diagnostic capability to enable remote monitoring and control. This includes substation Local Area Network (LAN) communications between end devices to remote terminal unit or communications processor, replacing distribution oil circuit breakers (OCBs), replacing old electro-mechanical relays with new microprocessor-based relays with communications capability, and replacing aging battery cabinets.

Current State
A majority of the substation devices (*e.g.*, breakers) are operated manually, so substation operators/distribution linepersons must drive to a substation to operate such devices.

Desired State
Install two-way communications infrastructure that will allow remote monitoring, remote operation (*i.e.*, open, close, block, unblock, tag circuit breakers), and remote data acquisition of substation devices. Replace all distribution OCBs with state-of-the-art vacuum circuit breakers, replace or upgrade relays on circuits served from transformers rated 10 MVA and above, and replace battery cabinets in substations with at least 1 transformer rated 10 MVA or above.

Benefits
Customer – Shorter outage duration due to quicker response to real-time events; reduced risk of outages caused by breaker and/or relay misoperation.

Reliability – Enabled remote monitoring, remote operation, and remote data acquisition of substation devices; reduced risk of expanded outages due to breaker misoperation; reduced likelihood of breaker failure for which no spare or replacement part is available.

Operational – Improved connectivity to substation devices for remote monitoring and control; reduced risk of outages and/or abnormal system configurations caused by breaker misoperation; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – Outdated and problematic breakers replaced with reliable current state-of-the-art breakers; reliable power provided to substation equipment by new battery.

Risks of Not Doing Project
- Aging equipment will remain in service.
- Potential for longer response times to outages, longer duration outages.
- Increased number of momentary or sustained outages caused by breaker misoperation.

Distribution

Distribution Ground Line Pole Replacement

1st Year Budget: $9,841,000 **7 Year Budget:** $78,271,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project involves inspection of distribution and subtransmission wood poles for ground line decay, above ground decay, pole top damage, or other defects; identification of wood poles nearing end of life; and development of a mitigation plan to replace or structurally modify the poles to address the identified problems. Wood pole inspection is a long-standing practice used by utilities to manage the very large wood pole asset base. This program and its cycle time frame are consistent with industry standards.

Current State
The 587,000 distribution wood poles are inspected on a 12-year cycle, or nearly 49,000 poles are inspected annually with replacement of approximately 3,300 poles on average each year.

Desired State
Perform more proactive inspection so that over time poles are replaced and the average age of all 587,000 poles is decreased.

Benefits
Customer – Reduced duration of outages.

Reliability – Reduced outages due to decayed poles.

Operational – Reduced emergency replacement and reduction of after-hours work.

Integrity – Overall better system integrity by reducing equipment near end of life and building to current construction standards.

Risks of Not Doing Project
- Declining reliability and integrity of the system.
- Increased risk of structural pole failure.
- Restoration O&M would remain flat or possibly increase due to increased truck rolls.

Distribution

Facility Relocation / Community Improvement

1st Year Budget: $4,347,000 **7 Year Budget:** $35,393,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project involves relocation of electric facilities impacting traveled roadways. As roadways expand or traffic conditions change, situations occur that result in the need to replace facilities in a different location. This is applicable for both transmission and distribution line facilities.

Current State
Electric facilities impacting roadway development or traffic flow are relocated based on request or design review. Many of these projects are non-reimbursable.

Desired State
Develop a facility relocation fund to address poles or structures impacting roadway improvement or traffic changes. Improve response and funding reimbursement.

Benefits
Customer – Reduction in vehicle-related outages.

Reliability – Reduced risk of outages related to potential vehicle issues.

Operational – Reduced restoration costs associated with repairing equipment damaged by vehicle accidents.

Integrity – Aged facilities replaced; mitigated traffic issues.

Risks of Not Doing Project
- Continued flat or increased O&M spend.
- Missed opportunity for local economic development due to travel access restrictions.

Distribution

General Underground and Overhead Capital Replacement

1st Year Budget: $14,495,000 **7 Year Budget:** $113,011,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

The overhead portion of this program would incorporate several existing programs worked today (*i.e.*, distribution switch replacement, cutout replacement, and capacitor oil to vacuum switch replacement) and add focus to proactively replace equipment with poor performance (*i.e.*, retirement of deteriorated military service vaults, 35 kV static work, and circuit contingency development). The underground portion of this program will incorporate several existing programs, including, but not limited to, switch gear replacement, vault lid retrofit, switching module replacement, and network improvements.

Current State

Replacements of poorly performing and aging equipment are done as a combination of failure replacements and some proactive replacements.

Desired State

Accelerate proactive replacement to perform more of the aforementioned programs. Reduce the amount of time needed to positively improve the integrity of the distribution systems.

Benefits

Customer – Decreased outages.

Reliability – Reduced outage risk by proactively replacing aging and poor performing equipment.

Operational – Reduced outages and truck rolls from better proactive replacement of equipment.

Integrity – Increased integrity of the system due to replacement of poor performing equipment.

Risks of Not Doing Project

- Continued flat or increased customer outages.
- Continued flat or increased O&M spend.

Distribution

Hazard Tree Removal & Capital Clearing

1st Year Budget: $4,554,000 **7 Year Budget:** $35,168,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

Hazard tree removal is the proactive removal of dead, diseased, dying or leaning trees that pose a risk to the transmission and distribution system. Approximately 13% of all customer outages are associated with tree failures and 46% of all vegetation-related outages are caused by tree failure. All tree removal practices are inspected, surveyed and performed using approved standards.

Current State

This program is performed proactively at 775 miles per year on average.

Desired State

Increase proactive performance to cover nearly 1100 miles annually.

Benefits

Customer – Reduced tree failure outages and tree-caused interruptions.

Reliability – Reduced tree-related risks by proactively minimizing one of the largest outage-causing issues.

Operational – Fewer truck rolls equating to reduced O&M.

Integrity – Reduced number of potential hazards to lines.

Risks of Not Doing Project

- Continued outages and interruptions caused by unmanaged vegetation hazards.
- Flat or increased operating cost.
- Flat or increased outages.

Distribution

Integrated Volt-VAR Control (IVVC) – Distribution Line

1st Year Budget: \$3,207,000 **7 Year Budget:** \$110,815,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
The project includes distribution line capacitor bank controls, circuit conditioning, line regulators and controls, medium voltage sensors, changeout or correction of existing transformers, and circuit modeling and analysis. These activities will provide better regulated voltage all along a distribution line as the load changes, improve power quality for customers, reduce losses, and provide communication and added visibility into the distribution grid through adding sensors and microprocessor-based controllers. Most of the spending will be 2017-2020.

Current State
Voltages all along distribution circuits are not optimized. There are no medium voltage sensors installed on Indiana circuitry.

Desired State
Low secondary voltage issues will be corrected. There will be added visibility to the grid to enable more efficient distribution, lower losses, and increase modeling/analysis capabilities. Overall circuit voltage level will be more consistent from head to end of circuit.

Benefits
Customer – Increase customer voltage level to minimum standard; improved power quality; ability to proactively address issues prior to customer calling in a voltage complaint; estimated 1% energy reduction on impacted circuits resulting in reduced fuel cost for the customer.

Reliability – Correction of customer voltage level; improved voltage levels and VARs on circuit; reduced losses.

Operational – Improved operational intelligence through communication with capacitor and voltage regulator controllers; more efficient operation of distribution system due to lower line losses; improved diagnostic tools.

Integrity – Ability to identify non-functioning equipment; longer life expectancy of devices.

Risks of Not Doing Project
- Implementation of IVVC could not be accomplished on those circuits without new controls.
- Inoperative capacitor banks and voltage regulators will not be identified until an inspection is done on the capacitor bank.
- Less efficient operation of circuitry due to more losses on the system.
- Less ability to model the system.

Distribution

Integrated Volt-VAR Control (IVVC) – Substation

1st Year Budget: \$1,219,000 **7 Year Budget:** \$10,855,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project includes substation capacitor bank, Load Tap Changer (LTC), and voltage regulator controls. Existing substation capacitor, LTC, and voltage regulator controllers will be replaced with new microprocessor-based controllers to provide communications, status, and remote control which will improve power quality to customers.

Current State
There is a lack of state-of-the art controllers on substation capacitors, LTCs, and substation voltage regulators.

Desired State
Replace distribution substation capacitor controllers, transformer controllers, and substation voltage regulator controllers with new microprocessor-based controllers over 7 years.

Benefits
Customer – Improved power quality; estimated 1% energy reduction on impacted circuits resulting in reduced fuel cost for the customer.

Reliability – Real-time communications will ensure capacitor banks, LTCs, and voltage regulators are operating when needed.

Operational – Improved operational intelligence through communication with capacitor controllers, LTC controllers, and voltage regulator controllers.

Integrity – Improved identification of equipment that is not functioning properly due to a blown fuse or other condition.

Risks of Not Doing Project
- Implementation of IVVC could not be accomplished on those circuits without new controls.
- Inoperative capacitor banks, LTCs, and voltage regulators will not be identified until an inspection is done.

Distribution

Substation Animal Mitigation

1st Year Budget: $400,000 **7 Year Budget:** $14,131,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves installation of animal mitigation measures in substations where Distribution Automation or other projects are being performed, or in selected stations where additional animal mitigation methods such as animal-resistant fencing has been shown to be needed.

Current State

Substations in Indiana have been constructed using different design standards over the years, and have provided varying levels of resistance to outages caused by electrical contact with animals (*e.g.*, squirrels, raccoons, birds, snakes, *etc.*). Not all stations have animal mitigation thoroughly applied according to current design standards. Over the past several years, some stations with a significant history of animal-caused outages have had animal-resistant fencing installed, but proactive installation or upgrade of "cover-up" methods of animal mitigation has not occurred. Capital projects such as breaker replacement include current animal mitigation designs for the newly-installed equipment, but do not provide funding to address animal mitigation in the rest of the station.

Desired State

All substations are equipped with animal mitigation measures meeting current design standards.

Benefits

Customer – Fewer outages caused by electrical contact by animals.

Reliability – Reduced risk of outages caused by electrical contact by animals.

Operational – Reduced or avoided emergency repair or replacement or after-hours work.

Integrity – Reduced or avoided equipment damage by electrical contact by animals.

Risks of Not Doing Project

- Continued animal-caused outages and equipment damage, with associated repair costs.

Distribution

Substation Rebuilds

1st Year Budget: \$1,000,000 **7 Year Budget:** \$12,648,000

Expected Timeframe for Project Execution: 2015-2017

Project Description
Perform an overall rebuild or refurbishment of selected substations where an overall rebuild has been identified as the most cost-effective way of correcting multiple identified reliability or integrity issues.

Current State
Several substations have been identified with multiple equipment issues impacting reliability and integrity of the substation.

Desired State
The identified substations are rebuilt using modern equipment and standard designs. For example, a station with multiple aged and deteriorated transformers and associated switchgear can be rebuilt based on a single larger transformer and free-standing circuit breakers. In another example, a station which has experienced recurring outages and damage due to flooding of a nearby river can be rebuilt or relocated with the equipment at a higher elevation to prevent flood waters from reaching it. In a third example, a substation utilizing a protection scheme based on a high-speed transmission circuit grounding switch to interrupt faults on an aged wye-delta transformer with a separate aged grounding transformer can be rebuilt utilizing a single delta-wye transformer and primary fault current interrupting device.

Benefits
Customer – Reduced risk of outages related to substation equipment failure due to age and condition.

Reliability – Reduced risk of outages for customers served by the substation.

Operational – Reduction of operational concerns such as mobile substation installations required by outages.

Integrity – Outdated and problematic substation equipment replaced with reliable current state-of-the-art equipment.

Risks of Not Doing Project
- Continued customer outages and extensive repair costs associated with antiquated equipment.

Distribution

T-D Transformer Replacements

1st Year Budget: $160,000

7 Year Budget: $14,747,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves proactive replacement of substation transformers in Indiana that have known condition issues that put them at high risk for premature failure. Six distribution transformers have initially been identified for inclusion in this project; however, the project estimate assumes 15-20 transmission-to-distribution transformers will be identified during the 7-year program period.

Current State

Existing transformers under consideration have known conditions that indicate that they are at risk for premature and unexpected failure.

Desired State

New transformers that meet current design and manufacturing requirements will be installed.

Benefits

Customer – Reduced risk of long-term outages related to a transformer failure.

Reliability – Reduced risk of outages from failure of transformer and associated circuits.

Operational – Reduced risk of outages caused by transformer failure; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – High priority transformers replaced with reliable current state-of-the-art transformers; reduced risk of environmental cleanup due to oil discharge from failed transformers.

Risks of Not Doing Project

- High risk of long-term transformer outage associated with premature transformer failure.

Distribution

Transformer Load Tap Changer Replacement

1st Year Budget: $900,000 **7 Year Budget:** $9,304,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves replacement of transformer Load Tap Changers (LTCs) that are of outdated designs with higher-than-acceptable rates of failures or that require frequent maintenance outages with modern high reliability, low maintenance LTCs.

Current State

Transformers with existing "arcing in oil" type LTCs, which are antiquated in design, are considered to be not reliable and require significant maintenance investments compared to more modern designs.

Desired State

Transformers will be retrofitted or converted to the modern "Vacuum" type LTCs. The Vacuum type LTCs are extremely reliable and are low maintenance.

Benefits

Customer – Reduced risk of outage, voltage variances, or flicker exposure.

Reliability – Reduced risk of transformer outages and improved associated voltage regulation.

Operational – Reduced risk of outages, voltage variances, or flicker exposure caused by LTC misoperation; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – Outdated and problematic LTCs replaced with reliable current state-of-the-art LTCs; transformers set up for the future IVVC effort; reduced risk of environmental cleanup due to oil discharge from failed LTCs.

Risks of Not Doing Project

- Increased exposure to transformer outages.
- Increased exposure to voltage and flicker excursions.

Distribution

Transformer Retrofit

1st Year Budget: \$3,214,000 **7 Year Budget:** \$30,606,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

Legacy construction has varied greatly over the last 50 years. The transformer retrofit program brings all existing equipment to the current enterprise construction standard. This ensures that the arrester is placed on the load side of the fuse versus an older practice of placing them on the line side of the fuse. It addresses replacement of cutouts that have previous poor performance. It also includes replacing bare lead wire with covered lead wire, adding animal guards over all exposed bushings, and retrofit of all completely self-protected (CSP) type transformers. Overhead transformer outages represent one of the highest device type outages impacting the reliability of the distribution system.

Current State

Estimated completion at the current rate is approximately 40 years.

Desired State

The annual volume of units addressed will be doubled over the life of the program to speed the reduction in outage risk.

Benefits

Customer – Reduced outage frequency.

Reliability – Reduced risk of outages by proactively minimizing the potential for an outage.

Operational – Reduced truck rolls 24/7.

Integrity – Increased unit capacity for CSP transformers by 25% to 60% and increased life of transformer by superior surge protection, proactive oil leak mitigation, and protecting transformers from damage by wider range fuse protection.

Risks of Not Doing Project

- System reliability would continue to remain flat or possibly decline.
- Restoration O&M would remain flat or possibly increase by not reducing truck rolls.

Distribution

Underground Cable Replacement/Treatment

1st Year Budget: \$3,615,000 **7 Year Budget:** \$30,195,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves identification of medium voltage underground cables nearing end of life and performing a cable assessment for treatment or replacement. Underground cable installation started in the 1970s and became the default installation method for most residential customer connects in the 1980s and beyond. Duke Energy Indiana currently has an estimated 8471 miles of underground cable installed. Cable technology has continued to improve through the years and life expectancy continues to increase. Cable technology used during the 1970s was non-jacketed concentric neutral using high molecular weight insulation and is beyond anticipated life span. This type of cable currently experiences increased failure rates resulting in increased customer outages that can be of extended duration depending on the installation configuration. Currently the volume of 1970s and 1980s vintage cable is estimated at 87 miles and 677 miles, respectively.

Current State

This program replaces 44,000 feet and treats 111,700 feet of underground conductor on average per year.

Desired State

Program will be accelerated so that additional feet of cable and underground conductor will be treated or replaced. This will reduce the amount of time needed to replace older and less reliable cable.

Benefits

Customer – Reduced long duration outages.

Reliability – Reduced risk of outages by reducing aged cable.

Operational – Fewer truck rolls and less emergency replacement and after-hours work.

Integrity – Improved integrity due to having new or treated cable that is more reliable.

Risks of Not Doing Project

- Flat or reduced performance of underground medium voltage cable.
- Flat or increased customer interruptions and increased long duration interruptions.
- Increased repair cost.

Distribution

Vegetation Clearing, Rights-of-Way Acquisition, Facility Modification

1st Year Budget: \$3,000,000 **7 Year Budget:** \$21,000,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This program will allow for more purchasing of Rights-of-Way (ROW) and vegetation easements so less customer legal issues arise. Approximately 13% of all customer outages are associated with tree failures and 46% of all vegetation-related outages are caused by tree failure. This will allow for more trimming of trees and vegetation near lines to help reduce vegetation-related outages.

Current State

Acquisitions are performed on an as required, reactive basis.

Desired State

Vegetation issues will be reduced through proactive acquisition of ROW.

Benefits

Customer – Reduced tree failure outages and tree caused interruptions.

Reliability – Reduced tree-related risks by proactively minimizing one of the largest outage-causing issues.

Operational – Fewer truck rolls equating to reduced O&M.

Integrity – Reduced hazards to lines by more aggressively pursuing the removal of vegetation.

Risks of Not Doing Project

- Flat or increased operating cost.
- Flat or increased outages.

Transmission

69 kV Circuit Integrity Improvement

1st Year Budget: \$23,425,000 **7 Year Budget:** \$198,202,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This program involves re-building selected transmission lines or line sections which contain numerous aged or deteriorating components such as wood poles and cross-arms, insulators, conductor and static wire. As all of these components age and move past that stage of one or two components that are reaching the end of their life, it makes better sense to fix the problem entirely with a total rebuild rather and rehabilitating the line piece by piece. Lines will be selected based upon the reliability history of the line and/or the age and observed condition of the line components, and re-built to modern design standards with new components.

Current State
Many of the 69 kV circuits were serviced over 40 years ago with many of the lines being built back in the 1960s. Many of the 69 kV lines still have outdated construction such as Wishbone and Gulf Port construction styles. There are components such as cross-arms, insulators, static wire and conductors that are also considered outdated or have less than desired reliability.

Desired State
All affected lines should be in good working condition. New assets along with higher and more accurate design standards will make the system sturdier and more resilient. Outage durations will decrease with the reduction of simultaneous outages, requiring fewer response personnel.

Benefits
Customer – Reduced outages and lower duration of outages.

Reliability – Fewer outages and lower duration times due to lower equipment replacement needs.

Operational – Fewer outages leading to system imbalance; quicker system stabilization with less activity to maintain.

Integrity – No threat of insufficient strength of assets; more durable system.

Risks of Not Doing Project
- Increase in outage frequency due to higher vulnerability.
- Larger than necessary portions of the electric system de-energized during outages.
- Higher O&M costs due to the increase in maintenance activity.

Transmission

69/138 kV Substation Switch Motor Mechanisms

1st Year Budget: \$2,398,000 **7 Year Budget:** \$19,663,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves the installation of motor-operators and remote status and control capabilities on transmission line switches within substations. The condition of the existing switches will be evaluated, and deteriorated or problematic switches will be replaced or refurbished. This will improve the real-time information available to the System Operation Center about the status of these switches and allow remote operation for normal switching operations and for circuit reconfiguration following an outage without requiring personnel to travel to the switches to operate them manually.

Current State

There are a number of Transmission-to-Distribution substations where the 69 kV or 138 kV supply circuit "daisy chains" through the substation bus through two line switches and perhaps one or more bus tie switches, allowing a faulted section of line to be isolated by opening the line switches on either side of the faulted section, and the circuit reconfigured to restore power to the substations. However, in many cases, these switches are not equipped with motor-driven operators nor remote Supervisory Control and Data Acquisition (SCADA) status and control, and some stations have no SCADA available at all.

Desired State

All transmission line switches located within substations should be in good working condition and equipped with motor-operators and remote SCADA status and control capability for reconfiguring the system in response to system outages or routine switching requests.

Benefits

Customer – Faster evaluation of outages and restoration of service.

Reliability – Reduced outage duration by allowing faster restoration following an outage.

Operational –Better real-time information on system configuration provided to Operations personnel; allows routine switching to be performed without requiring travel to the switch.

Integrity – Ensures that the existing switches are functional and provide the appropriate switching capability for the system configuration.

Risks of Not Doing Project

- Continued need for personnel to drive to the substation to operate the switch and verbally report its status back to the System Operations Center.
- Longer restoration times than could be achieved using remote supervisory control.
- Increased labor cost of routine switching.

Transmission

Aluminum H Structure Replacement

1st Year Budget: \$2,534,000 **7 Year Budget:** \$252,359,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

The purpose of this project is to minimize exposure to failures, large customer outage times, and O&M expenditures on real-time repairs. Several circuits have original aluminum H-frame structures. On several selected circuits, all of the aluminum H-Frame structures will be replaced with steel structures, and, on remaining circuits, additional direct-embedded guyed steel pole H-frame structures, will be installed to decrease exposure to potential failures.

Current State

Aluminum H-Frame structures have suffered structural failure during high wind events, which in turn has caused failure of numerous structures on the circuit. In the past, intermediate dead-end structures composed of steel towers have been installed on a number of circuits to reduce the exposure to failure.

Desired State

All affected lines should be in good working condition. New intermediate assets will make the 345 kV system sturdier. Outage durations will decrease with the reduction of outage exposure.

Benefits

Customer – Reduced duration of outages.

Reliability – Fewer assets involved in events; less structural damage on surrounding assets near events.

Operational – Fewer outages leading to system imbalance; quicker system stabilization with less activity to maintain.

Integrity – More durable system.

Risks of Not Doing Project

- Line assets that fail will continue to cause damage to surrounding assets which may cause an increase in failing assets.
- Larger than necessary portions of the electric systems will be de-energized for longer periods of time as well as drive up O&M costs for emergency repair situations.
- Electric system will be more vulnerable.

Transmission

Bushing Replacement

1st Year Budget: $721,000 **7 Year Budget:** $6,470,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves completion of a targeted replacement of bushing types with a known history of problems or failures. While primarily targeted at General Electric Type U bushings, Westinghouse Type S and Westinghouse Type OS bushings (both of which contain PCBs) may be included as well. Proactive replacement of these bushings will reduce the risk of catastrophic failure leading to customer outage and/or disruption of the bulk electric system. Failure prevention also reduces the risk of a bushing damaging or destroying more expensive pieces of equipment within the substation and reduces overall maintenance costs.

Current State

Current practice is to replace specific bushings that have shown a trend of increasing power factor (*i.e.*, are "trending toward failure") or where targeted bushing styles exist in transformers that have an outage scheduled for other reasons. Many bushings of the targeted styles remain in service.

Desired State

Replace all GE Type-U, Westinghouse Type S and Westinghouse Type OS bushings within 7 years.

Benefits

Customer – Reduced risk of outages caused by bushing failure.

Reliability – Reduced risk of unplanned outages from failed bushing; reduced likelihood of bushing failure damaging the transformer or other nearby equipment.

Operational – Reduced risk of outages and/or abnormal system configurations caused by bushing failure; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – Problematic bushing styles replaced, potentially extending the useful life of the transformer; reduced risk for environmental cleanup of PCB or oil discharge.

Risks of Not Doing Project

- Elevated risk of bushing failure, which would lead to unplanned outages and reliability impacts.
- Failure of a bushing can also damage or destroy the transformer on which it is installed.

Transmission

Galloping Conductor Mitigation

1st Year Budget: \$3,400,000 **7 Year Budget:** \$23,304,000

Expected Timeframe for Project Execution: 2015-2019

Project Description
This project involves reconductoring portions of the 138 kV and 230 kV systems to mitigate galloping conductor issue.

Current State
Certain transmission line conductors located in rural plains areas have exhibited a very high probability of experiencing wind-induced "galloping" conductor events, which can damage conductors, insulators or other transmission line components and cause circuit outages. Previously installed anti-galloping devices such as interphase spacers and dampeners have not produced results for periods of time comparable to the length of life of new conductor. Several identified transmission circuits have previously been mitigated by reconductoring the circuit with specialized conductors, but other 230 kV circuits and 138 kV circuits remain to be mitigated.

Desired State
Momentary and sustained outages on treated lines will be reduced and/or eliminated by reconductoring the remaining circuits.

Benefits
Customer – Reduction of customer outages and durations.

Reliability – Reduction in outages as well as outage durations.

Operational – Fewer outages leading to system imbalance; lower outage O&M costs for repetitive momentary interruptions that lock out the system, requiring someone to go check the area for restoration.

Integrity – Less damage to conductors and static wire.

Risks of Not Doing Project
- Continued outages from galloping conductor.
- Continued outage O&M costs for repetitive momentary interruptions that lock out the system, requiring someone to go check the area for restoration.
- Electric system is more vulnerable.

Transmission

General Transmission Capital Replacement

1st Year Budget: \$19,325,000 **7 Year Budget:** \$102,597,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project provides overall funding for a number of smaller capital replacement efforts which reduce outage risk through proactive replacement of aged, outdated, or problematic transmission line and substation equipment. Examples of activities which could be included under this funding project could include proactive replacement of overhead ground wire or cross-arms on targeted circuits; upgrading protection and mitigation; and/or replacing various substation equipment such as lightning arresters, remote terminal units, switches, *etc.*

Current State

Deteriorated static wires continue to result in large outage duration hours due to breaking in high winds and failing under low magnitude lightning strokes. Deteriorated cross-arms are likely to break and lead to downed conductors during high winds. A number of circuits currently are configured with an undesired system of protection. Certain substation lightning arresters are of an outdated and more failure-prone technology. Certain transmission switches are deteriorated or problematic and should be replaced to ensure proper functioning and reliability.

Desired State

Circuits will have lightning protection that can handle the designed protection schemes. Damaged, deteriorated, or outdated cross-arms will be replaced. The system will be stronger and more resilient.

Benefits

Customer – Reduction of customer outages, durations, voltage sags, and quick blinks.

Reliability – Reduction in outages as well as outage durations.

Operational – Fewer outages leading to system imbalance; lower outage O&M costs for repetitive momentary interruptions that lock out the system, requiring someone to go check the area for restoration.

Integrity – System less affected by lightning and other natural causes.

Risks of Not Doing Project

- Continued outages from lightning with low magnitudes, broken cross-arms, and weaker 35 kV system.
- Continued outage O&M costs for repetitive momentary interruptions that lock out the system, requiring someone to go check the area for restoration.
- Electric system is more vulnerable.

Transmission

T-T Transformer Replacements

1st Year Budget: $5,000,000 **7 Year Budget:** $8,207,000

Expected Timeframe for Project Execution: 2016-2019

Project Description
This project involves proactively replacing substation transformers in Indiana that have known condition issues that put them at high risk for premature failure. One transmission-to-transmission transformer has initially been identified for inclusion in this project; however, the project estimate assumes additional large transmission-to-transmission transformers will be identified during the program period.

Current State
Existing transformers under consideration have known conditions that indicate that they are at risk for premature and unexpected failure.

Desired State
New transformers that meet current design and manufacturing requirements will be installed.

Benefits
Customer – Reduced risk of long-term outages related to a transformer failure.

Reliability – Reduced outage risk from failure of transformer and associated circuits.

Operational – Reduced risk of outages caused by transformer failure; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – High priority transformers replaced with reliable current state-of-the-art transformers; reduced risk of environmental cleanup due to oil discharge from failed transformers.

Risks of Not Doing Project
- High risk of long-term transformer outage associated with premature transformer failure.

Transmission

Transmission Breaker Replacement

1st Year Budget: $7,173,000 **7 Year Budget:** $54,223,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves replacement of outdated transmission oil circuit breakers (OCBs) and high-volume SF6 gas circuit breakers (GCBs), typically in conjunction with replacement of outdated transmission relays. All OCBs have been identified as an outdated technology and due to age, wear, *etc.*, are becoming increasingly difficult to maintain and keep functioning per the designed specifications. Certain older-model SF6 GCBs contain large quantities of SF6 and some exhibit high leakage rates of the SF6, which is a greenhouse gas. Presence of an outdated circuit breaker in and of itself will typically not be treated as a primary project driver during this program, but there is a high correlation between outdated breakers and outdated relays to be upgraded. Replacing the outdated circuit breaker in conjunction with the relay replacement project saves an estimated $65,000 to $75,000 per breaker in reduced engineering design and construction costs versus performing these replacements as separate projects.

Current State

An average of 10 problematic transmission breakers per year have been replaced over the past few years but this pace will not eliminate use of these breakers within a reasonable timeframe.

Desired State

All transmission OCBs and identified high volume SF6 GCBs will be replaced by state-of-the-art SF6 circuit breakers within the next 15 years.

Benefits

Customer – Reduced risk of outages caused by breaker misoperation.

Reliability – Reduced risk of expanded outages due to breaker slow operation or misoperation; reduced likelihood of breaker failure for which no spares or replacement parts are available.

Operational – Reduced risk of outages and/or abnormal system configurations caused by breaker misoperation; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – Outdated and problematic breakers replaced with reliable current state-of-the-art breakers; reduced risk of environmental cleanup due to oil discharge from failed breaker.

Risks of Not Doing Project

- Continue to have outdated OCBs/GCBs in service with increasing difficulty and expense to keep them functioning properly, resulting in increasing number of momentary or sustained outages on the Transmission and Sub-Transmission systems caused by breaker misoperation.
- Continuing risk of catastrophic failure of OCBs, resulting in discharging oil and environmental cleanup expense, and reporting.

Transmission

Transmission Ground Line Pole Replacement

1st Year Budget: \$2,034,000 **7 Year Budget:** \$59,534,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project involves inspection of transmission wood poles for ground line decay, above ground decay, pole top damage, or other defects; identification of wood poles nearing end of life; and development of a mitigation plan to replace with steel or structurally modify the poles to address the identified problems. Wood pole inspection is a long-standing practice used by utilities to manage the very large wood pole asset base. This program and its cycle time frame are consistent with industry standards.

Current State
Both transmission and distribution wood poles are inspected on a 12 year cycle, with replacement of the worst poles.

Desired State
Poles will be replaced more proactively, resulting from a more frequent inspection cycle and expanded condition criteria which would identify pole replacement.

Benefits
Customer – Reduced long duration outages.

Reliability – Reduced risk of outages due to decayed poles.

Operational – Reduced emergency replacement and reduction of after-hours work.

Integrity – Overall better system integrity by reducing equipment near end of life and built to today's construction standards.

Risks of Not Doing Project
- Reliability and integrity of system would decline.
- Increased risk of structural pole failure.
- Restoration O&M would remain flat or possibly increase due to increased truck rolls.

Transmission

Transmission Hazard Tree Removal

1st Year Budget: $1,680,000 **7 Year Budget:** $17,614,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
Hazard tree removal is the proactive removal of dead, diseased, dying or leaning trees that pose a risk to the transmission and sub-transmission circuits. Approximately 13% of all customer outages are associated with tree failures and 46% of all vegetation-related outages are caused by tree failure. All tree removal practices are inspected surveyed and performed using approved standards.

Current State
The pace of removing hazard trees is not keeping up with the increased number of such trees which is thought to be caused by recent weather conditions (drought, *etc.*) and new insect threats (*e.g.* emerald ash borer).

Desired State
There will be identification and removal of more hazard trees per year in line with the increased number of such trees that are occurring due to environmental factors.

Benefits
Customer – Reduction of tree failure outages and tree-caused interruptions.

Reliability – Reduced tree-related risks by proactively minimizing one of the largest outage-causing issues.

Operational – Fewer truck rolls equating to reduced O&M.

Integrity – Reduced number of hazard trees that threaten the integrity of the system.

Risks of Not Doing Project
- Continued outages and interruptions caused by unmanaged vegetation hazards.
- Flat or increased operating cost.
- Flat or increased outages.

Transmission

Transmission Line Switch Upgrade & Automation

1st Year Budget: \$1,639,000 **7 Year Budget:** \$19,600,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project involves installing motor-operators and remote status and control capabilities on selected switches on transmission and sub-transmission circuits (outside of substations). During this process, the condition of the existing switches will be evaluated and deteriorated or problematic switches will be replaced or refurbished. This will improve the real-time information available to the System Operation Center about the status of these switches and allow remote operation for normal switching operations and for circuit reconfiguration following an outage without requiring personnel to travel to the switches to operate them manually. This will decrease load restoration time following outages plus save labor costs during routine switching.

Current State
There are approximately 629 existing transmission and sub-transmission line (*i.e.*, outside of substations) switches in Indiana. Essentially none of these switches currently is equipped with motor-driven operator nor remote Supervisory Control and Data Acquisition (SCADA) status and control.

Desired State
Transmission and sub-transmission line switches that are at critical junction points for reconfiguring the system in response to system outages or routine switching requests will all be in good working condition and equipped with motor-operators and remote SCADA status and control capability.

Benefits
Customer – Faster restoration of service after outages.

Reliability – Reduced outage duration through faster evaluation and restoration.

Operational – Better real-time information on system configuration provided to Operations personnel; routine switching performed without requiring physical travel to the switch.

Integrity – Ensured functionality of the existing switches; appropriate switching capability for the system configuration provided.

Risks of Not Doing Project
- Continued need to send personnel to operate the switch and verbally report its status back to the System Operations Center.
- Longer restoration times than could be achieved using remote supervisory control.
- Increased labor cost of routine switching.

Transmission

Transmission Relay Upgrade – Tiers I & II

1st Year Budget: $4,114,000 **7 Year Budget:** $75,694,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project involves replacing transmission relays that are outdated or poorly-performing types, thereby reducing the risk of relay misoperation leading to customer outage and/or disruption of the bulk electric system. Replacing the older styles with modern relays also provides additional capabilities that allow improved restoration following a fault. Tier I and Tier II relays are of styles that have been identified as outdated and/or troublesome.

Current State
Replacement of these relays is not at a rate to eliminate these relays in a reasonable timeframe.

Desired State
All Tier I and Tier II relay terminals/protection groups containing relays of the targeted styles will be replaced using current state-of-the-art relays and protection schemes.

Benefits
Customer – Reduced risk of outages due to relay misoperation; faster service restoration.

Reliability – Reduced risk of unplanned events from failed relays; reduced likelihood of relay failure for which no spare relays or replacement parts are available.

Operational – Reduced risk of outages and/or abnormal system configurations cause by relay misoperation; reduced or avoided emergency repair or replacement or after-hours work.

Integrity – Outdated and problematic relay styles replaced with reliable state-of-the-art relays.

Risks of Not Doing Project
- Continuing difficulty keeping these outdated relays in calibration and functioning properly.
- Increasing risk or rate of unplanned events from failed relays.
- Increasing likelihood of relay failure for which no matching spare relay or replacement parts are available, leading to prolonged repair or replacement time.

Other T & D

Communication Replacement (T&D Vehicle Radio System)

1st Year Budget: $0 **7 Year Budget:** $30,000,000

Expected Timeframe for Project Execution: 2017-2018

Project Description
Communication and quick response time is critical for operational and safety purposes. Mobile data is becoming more of a required service to meet customer needs and real-time operational expectations. This project involves replacement of the existing Integrated Digital Enhanced Network (IDEN) radio system. This is the base-to-truck, truck-to-truck and Meter Data Management System (MDMS) communication system.

Current State
The existing radio technology is nearing end of life and the hardware will no longer be supported. Data transfer rates are very slow, making true mobile data capability very limited. Coverage has dead spots due to the vast service territory.

Desired State
Better communication and data coverage including improved data rate for full mobile data capability will be provided. Technology is still undetermined and will be evaluated over the next 12 months. This may result in new hardware installation; however, there is also the possibility of migrating to open carrier instead of private.

Benefits
Customer – Increased availability of operational information to customer through Mobile Data Terminals (MDTs) and direct communication of information.

Reliability – Radio system reliability improvement due to aging system and lack of manufacturer support.

Operational – Critical communication including voice and data provided for operation of the electric system; improved safety of the work force, emergency communication and direction of work and system information.

Integrity – Current system is aging and will no longer be supported by the manufacturer.

Risks of Not Doing Project
- Increased response time for safety and operational purposes.

Other T & D

Distribution Operations Center Renovations

1st Year Budget: $5,000,000 **7 Year Budget:** $35,000,000

Expected Timeframe for Project Execution: 2015-2021

Project Description
This project involves renovation of Indiana Operations Centers to provide safe and productive workspaces for field operations.

Current State
Most Indiana Operations Centers are outdated both in office conditions, but also in operational effectiveness on the site.

Desired State
Provide effective and efficient field operations sites to provide employees a productive work environment with improvements in building conditions and reliability, as well as improvement in site conditions.

Benefits
Customer – Decreased duration of customer outages.

Reliability – Decreased duration of outages and improved reliability of building systems during critical periods such as storm restoration.

Operational – Increased productivity of employees through improved reliability of building systems during critical periods such as storm restoration, via generator installation to continue building operations through outage period, and implementation of storm centers within operations centers; improved functionality of workspace (*e.g.*, office, pole yard layout, materials warehousing), adding productivity efficiencies to employees and improves operational effectiveness of workers.

Risks of Not Doing Project
- Lower productivity.
- Less efficient operations.
- Inability to utilize updated technology.

Other T & D

Economic Development Site Readiness

1st Year Budget: \$11,230,000 **7 Year Budget:** \$114,717,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project will make industrial sites more attractive by installing new line extensions for both transmission and distribution. In addition, this project will increase customer interest by providing more reliable network feeds and modernization of existing equipment. Creating a proactive approach to site-readiness capacity upgrades and a redundant networked system will help draw large customers because of their short selection process timeline. This project will ultimately support the development and attraction of businesses throughout the state and quickly create new jobs, both directly and indirectly for Hoosier workers.

Current State

There is no current economic development funding available to make industrial parks more attractive to customers.

Desired State

The development of new and existing industrial parks for the attraction of large businesses will be actively funded.

Benefits

Customer – Large customers will be attracted to site-readiness and increased network redundancy.

Reliability – Potential for reliability to increase at the sites involved due to redundant feeds to customers with a networked system.

Operational – Upgrades, modernization, and redundancy of facilities may reduce emergency truck rolls.

Integrity – Some outdated facilities will be upgraded and modernized to today's standards; potential increase in capacity.

Risks of Not Doing Project

- Loss of large industrial customers in vacant industrial sites.
- Loss of a large amount of new Hoosier jobs, both direct and indirect.

Other T & D

Envision Center

1st Year Budget: \$1,500,000 **7 Year Budget:** \$3,000,000

Expected Timeframe for Project Execution: 2015-2016

Project Description

This project involves constructing an Envision Center in Indiana (on or near the Duke Energy Plainfield Campus) that will house an energy learning center demonstrating to visitors how our energy infrastructure is changing with new emerging energy sources, technologies, and the modernization of our infrastructure grid. Duke Energy is directly involved with this modernization and has the opportunity to educate regulatory bodies, industries, and the public to understand this new energy model.

Current State

No such Envision Center exists today in the State of Indiana.

Desired State

Create an Envision Center that will serve to train and educate all stakeholders about the changing landscape of the energy environment, resulting in better informed stakeholders and economic growth opportunities to the State of Indiana.

Benefits

Customer – Increased consumer education provided at a location that is publicly accessible to regulators, commercial business, schools, industry, and general public.

Operational – Increased operational effectiveness of Indiana operations through employee training (*e.g.*, operational training, call center functions, engineering, business development).

Risks of Not Doing Project

- Less education of regulators and other stakeholders regarding energy issues, both existing and emerging.

Other T & D

Mobile Deployment & Innovation

1st Year Budget: $1,000,000 **7 Year Budget:** $2,500,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

This project involves deployment of mobile technology to all field workers to improve real-time dispatch, status and event support. This includes all line, service, design or customer-facing field workers. This project includes hardware, software, and communication support, and ongoing technology innovation.

Current State

A limited number of employees have mobile technology with the ability of two-way real-time dispatch and communication or work requests, location, status, *etc.* With such a low number of field mobile devices, the customer experience, many times, is limited by availability of technology. Reliance today is on radio or cell phone communication.

Desired State

Deployment of mobile data terminals (MDT) or other field devices will allow real-time two-way communication with first responders and field workers. MDT will provide real-time dispatch of routine work and emergency work, and the ability to provide updates on job status, location, and outage cause, along with many other pieces of information.

Benefits

Customer – Improved customer experience through increased performance and availability of information and status.

Reliability – Improved information flow and resource utilization.

Operational – Improved information flow between dispatch and field workers; reduction of first-hand communications and translation to data systems; operational improvement through electronic dispatch and data acquisition.

Integrity – Improved data integrity.

Risks of Not Doing Project

- Missed opportunity to improve operational efficiency and data integrity.
- Missed opportunity to improve information flow to increase customer experience.

Other T & D

Real Time Customer Personal Mobile Device (PMD) Communication

1st Year Budget: \$1,000,000 **7 Year Budget:** \$1,500,000

Expected Timeframe for Project Execution: 2015-2016

Project Description
This project involves installation of a customer communications software system. This system will relay information to a customer based on their chosen method which could be text, email, phone call or other. This system will tie with systems such as outage management, customer billing, *etc.*, and proactively communicate with customers based on preferred method of communication and information requested such as outage notification, estimated time of restoration (ETR), order completion, billing milestones, or other important information.

Current State
Customer communication is primarily through phone call, recorded message and interactive voice response (IVR).

Desired State
There will be real-time connection to customers based on their choice of communication method and type of information they would like to receive.

Benefits
Customer – Increased information and decision making ability; improved customer relations through sharing of information.

Integrity – Increased data integrity.

Risks of Not Doing Project
- Missed opportunity for customer experience improvement.
- Missed opportunity to use advanced technology to keep up with customer expectations.

Other T & D

TCC/DCC Operation Centers Upgrade

1st Year Budget: \$7,900,000 **7 Year Budget:** \$11,600,000

Expected Timeframe for Project Execution: 2015-2017

Project Description
This project involves construction of a modernized Transmission Control Center (TCC) and Distribution Control Center (DCC) facility.

Current State
The existing TCC/DCC operations rooms are becoming dated in technology, infrastructure, and in meeting current NERC security requirements. This facility has had some infrastructure updates, particularly electrical and redundant electrical, generator supplies, but still remains dated with respect to HVAC, exterior/interior finishes, functional layout of work groups, *etc.*, and desired redundant systems in this critical work space. Duke Energy maintains two Indiana TCC/DCC locations which include backup sites in remote locations.

Desired State
There will be a newly constructed facility with updated infrastructure, security improvements to current NERC standards, functional workspace for the operations personnel, and desired redundancy to provide continued operations under severe weather conditions, electrical conditions and threats. The new design will allow reduction to one location with the backup site included in the one location.

Benefits
Customer – Shorter duration outages through proactive identification and action on outages.

Reliability – Proactive identification and action on outages leading to shorter duration.

Operational – Full utilization of the distribution management system (DMS) for increased crew dispatch efficiency, increased fault location identification and implementation of Integrated Volt-VAR Control (IVVC) for overall decreased restoration time system optimization; greater operational efficiencies with backup at same site.

Risks of Not Doing Project
- No ability to leverage new technology.
- Continued need to maintain two locations.
- Continue to self-report technical feasibility exceptions with corrective actions to fix at a later date.

Other T & D

Transmission & Substation Asset Performance Center

1st Year Budget: \$300,000 **7 Year Budget:** \$300,000

Expected Timeframe for Project Execution: 2015

Project Description
This project involves development of a Transmission & Substation Asset Performance Center with the following functionality:

- Full analysis of all transmission line and substation events (NERC Bulk Electric System);
- Lightning correlation for events;
- Fault location for outages;
- Fault analysis of outages;
- Analysis and documentation of each event and carrying out misoperation protocols; and
- Providing input to the initial configuration of the monitored equipment, trigger levels, digital channel information, *etc.,* with updating of configurations as necessary.

Current State
The duties are handled by two different teams. There are no full time fault analysis duties. There are no dedicated facilities to perform duties.

Desired State
There will be one team handling the duties of analyzing transmission outages. There will be real-time analysis to help outage follow-up crews. There will be reduced outage restoration time.

Benefits
Customer – Quicker restoration times; more reliable service due to more frequent analysis.

Reliability – Reduced risk due to increased analysis, more accurate data on more outages, more efficient O&M expenditures.

Operational – Fewer outages which cause system imbalance; lower outage O&M costs for repetitive momentary interruptions that lock out the system, requiring someone to go check the area for restoration.

Integrity – Identifies the weak points in the system.

Risks of Not Doing Project

- Continued delayed analysis rather than real-time.
- Less efficient time management and O&M expenditures.

Vegetation Management O&M

Distribution Vegetation Clearing O&M

1st Year Budget (O&M): $1,530,000 **7 Year Budget (O&M):** $17,130,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

Distribution vegetation clearing is a comprehensive approach to vegetation line clearing focused on a ground to sky clearance including treatment where appropriate to protect distribution line facilities effectively from vegetation-related interruption and to promote improved access to facilities for maintenance. The current rate structure includes $13.35 million per year for vegetation treatment. To maintain proper clearance and operability, the actual annual expense is $14.88 million. This program includes additional operational funding of $1.53 million per year to support this comprehensive approach.

Current State

The vegetation trim cycle is 5.5 years.

Desired State

A comprehensive vegetation management approach with 5-year trim cycle will be employed, with migration to ground-to-sky clearance with increased herbicide treatment where applicable.

Benefits

Customer – Outage reduction and improved vegetation management tactics.

Reliability – Reduction in risk of vegetation-related outages (the largest contributor to distribution system outages) and restoration time.

Operational – Increased facility access and improved restoration time.

Integrity – Reduction in vegetation-related structure damage.

Risks of Not Doing Project

- Number of vegetation-related reliability outages will remain flat or potentially increase.
- Duration of vegetation-related outage durations will remain flat or potentially increase.

Vegetation Management O&M

Transmission Vegetation Clearing O&M

1st Year Budget (O&M): $4,000,000 **7 Year Budget (O&M):** $31,400,000

Expected Timeframe for Project Execution: 2015-2021

Project Description

Vegetation clearing of transmission and sub-transmission circuit right-of-way is a comprehensive approach to vegetation line clearing focused on a ground to sky clearance including treatment where appropriate to effectively protect transmission line facilities from vegetation-related interruption and to promote improved access to facilities for maintenance. The current rate structure includes $3.5 million per year for vegetation treatment, although the actual annual expense recently has been $7.5 million to support this comprehensive approach to maintaining proper clearance and operability. This program consists of the operational funding of the $4 million per year difference.

Current State

The vegetation trim cycle is 5.5 years.

Desired State

A comprehensive vegetation management approach with 5-year trim cycle will be employed, with migration to ground to sky clearance to the full width of the right-of-way (which varies by circuit voltage level) with increased herbicide treatment where applicable.

Benefits

Customer – Reduced outages and improved vegetation management tactics.

Reliability – Reduction in risk of vegetation-related outages due to comprehensive vegetation line clearing.

Operational – Improved operability due to increased facility access and improved restoration time.

Integrity – Improved system integrity through a reduction in vegetation-related structure damage.

Risks of Not Doing Project

- Potential for regulatory fines or increased scrutiny for vegetation management non-compliance on NERC-regulated circuits.
- Vegetation-related reliability outages and durations will remain flat or potentially increase.

EXHIBIT D

Attach. CDK-1

Duke Energy – Ohio

SmartGrid Cost / Benefit Model (Project Financial Model)

Assumptions, Inputs, and Results

Report Prepared by:

Chris Kiergan (KEMA)

July 24, 2008

SmartGrid Cost / Benefit Model – DE-Ohio

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Duke Energy

SmartGrid Cost / Benefit Model – DE-Ohio

Model Overview

The financial model for the SmartGrid Initiative is a cost / benefit model that captures the overall economics of the project through incremental project financial analysis.

- The analysis models capital expenditures, O&M expenses, and associated benefits for 2009-2028, as well as 20-year NPV values.
- The analysis does **not** attempt to model revenue recovery values or rate impacts; though an integral part of a regulatory filing, revenue recovery and rate impacts will be modeled by the Rates department using the data (inputs and results) in this model as a basis.
- The model is an Excel-based tool that supports financial analysis and is being used as a basis for management decisions

Deployment Timelines

There are different deployment timelines in Ohio for the electric meters (including communications equipment), gas modules (including communications equipment), information technology, and distribution automation based upon projected resource requirements of the Duke Energy-wide implementation. Deployment is modeled as starting in 2009.

Deployment Schedule	Year 1	Year 2	Year 3	Year 4	Year 5
	2009[1]	2010	2011	2012	2013
Electric Meters	17%	34%	34%	10%	5%
Gas Modules	19%	34%	34%	10%	3%
Information Technology Costs	20%	30%	30%	10%	10%
Distribution Automation	20%	20%	20%	20%	20%

Note 1: 2009 deployment includes electric meters and gas modules (and associated communications equipment) deployed in 2008 (Electric meters: 7% in 2008, 10% in 2009; Gas modules: 9% in 2008, 10% in 2009)

The final year of the deployments is primarily reserved for changing out or retrofitting the final, hard-to-get to / hard-to-schedule / non-typical-solution meters, estimated to be no more than 5% of the total meters changed out. Below are the steps used in determining the electric meter and gas module deployment schedules listed above:

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
	2008	2009	2010	2011	2012	2013
Current Plan - Electric Meters	55,000	75,000				
Current Plan - Gas Modules	42,000	50,000				
Proposed 5-Year Implementation	97,000	125,000	440,000	443,000	127,000	-
Adjustment for only 95% getting changed-out during the four-year implementation - The other 5% take an extra year to finish - hard to get to, different or difficult communications, etc.	97,000	125,000	418,000	420,850	120,650	50,500
	Year 0	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Calendar Year Schedule	97,000	125,000	418,000	420,850	120,650	50,500
Calendar Year Schedule - Electric	55,000	75,000	256,500	258,249	74,035	37,216
Calendar Year Schedule - Gas	42,000	50,000	161,500	162,601	46,615	13,284
Overall Meter/Module Deployment Schedule	7.9%	10.1%	33.9%	34.2%	9.8%	4.1%
Meter/Module Deployment Schedule - Rounded	**8.0%**	**10.0%**	**34.0%**	**34.0%**	**10.0%**	**4.0%**
Electric Meter Deployment Schedule	7.3%	9.9%	33.9%	34.2%	9.8%	4.9%
Electric Meter Deployment Schedule - Rounded	**7.0%**	**10.0%**	**34.0%**	**34.0%**	**10.0%**	**5.0%**
Gas Module Deployment Schedule	8.8%	10.5%	33.9%	34.2%	9.8%	2.8%
Gas Module Deployment Schedule - Rounded	**9.0%**	**10.0%**	**34.0%**	**34.0%**	**10.0%**	**3.0%**

Quantity of Meters

In Ohio today, there are 722,941 electric meters that will be replaced with the new metering infrastructure. This includes all meters that are less than 500 kW. Additionally, there are 453,515 gas meters that will be retrofitted with gas modules in order to be a part of the SmartGrid infrastructure. The total number of meters to be replaced or retrofitted is 1,176,456. (This does not include all of the new locations that will be set with the new metering technology or module upon being initially metered.)

Classification of Meters	Meters Included in Classification	Number of Ohio Meters (March/June 2008)
Standard Residential electric meter	• Non-demand--class 200	619,544
Very Small Commercial / Special Residential meters	• Demand--class 200 • Non-demand--class 100, class 320, and network • All Itron style AMR meters • All pre-AMR remotes, time switches	65,583
Special Small Commercial / Small Commercial / Small Industrial meters	• All three phase self contained non-demand meters • Single phase demand--class 100, 200, 320, and network • All single phase TOU, MM/IDR • Self contained - All standard Vectrom meter accounts including load research, TOU/MM (read by meter reading), pulse output, and class 320	18,304
Medium Commercial / Industrial meters	• Transformer type--single phase and three phase standard • Vectron meter accounts including load research TOU (read by meter reading), and pulse output	19,530
Large Commercial / Industrial / Special Small Commercial / Industrial meters	• All modem Vectron meters, solid state recorders, and Fulcrum meters (mostly accounts > 500 KW)	2,459
Special Commercial / Industrial meters	• Generation customers • SCADA ready meters • (Quantum, Q1000, and GEM meters)	161
Total Electric Meters		**725,561**
Total Electric Meters to be Replaced (excludes the last two classifications)		**722,941**
Residential gas meters	• All residential gas meters • Commercial meters for residential purposes	418,713
Commercial / Industrial gas meters	• Commercial gas meters • Gas farm meters • Industrial gas meters • Governmental gas meters	34,802
Total Gas Meters to be Retrofitted		**453,515**
Total Meters		**1,179,076**
Total Meters to be Replaced or Retrofitted		**1,176,456**

From a modeling perspective, electric meters are listed in two categories:

- Residential – Encompasses meters in the first classification (Standard Residential electric meters)
- Commercial / Industrial < 500 kW – Encompasses meters in the second through fourth classifications (Very Small Commercial / Special Residential meters, Special Small Commercial / Small Commercial / Small Industrial meters, Medium Commercial / Industrial meters)

From a modeling perspective, gas meters are listed simply in the two categories appearing in the table above: Residential gas meters and Commercial / Industrial gas meters.

Electric: The initial number of electric meters is grown in the model based on annual meter growth rates shown in the next section. This results in the following Ohio electric meter installations:

Year	Calendar Year	Number of Electric Meters with AMI			Meters Installed in the Specified Year		
		Residential	Commercial / Industrial < 500 kW	Total	Residential	Commercial / Industrial < 500 kW	Total
1	2009	106,383	17,735	124,118	106,383	17,735	124,118
2	2010	322,106	53,679	375,785	215,723	35,944	251,667
3	2011	541,507	90,221	631,728	219,401	36,542	255,943
4	2012	610,375	101,694	712,069	68,868	11,473	80,341
5	2013	647,837	107,980	755,817	37,462	6,286	43,748
6	2014	653,092	108,920	762,012	5,255	940	6,195
7	2015	658,351	109,872	768,223	5,259	952	6,211
8	2016	663,598	110,824	774,422	5,247	952	6,199
9	2017	668,741	111,783	780,524	5,143	959	6,102
10	2018	673,780	112,755	786,535	5,039	972	6,011
11	2019	678,745	113,738	792,483	4,965	983	5,948
12	2020	683,636	114,745	798,381	4,891	1,007	5,898
13	2021	688,419	115,764	804,183	4,783	1,019	5,802
14	2022	693,113	116,801	809,914	4,694	1,037	5,731
15	2023	697,725	117,855	815,580	4,612	1,054	5,666
16	2024	702,268	118,925	821,193	4,543	1,070	5,613
17	2025	706,734	120,013	826,747	4,466	1,088	5,554
18	2026	711,129	121,119	832,248	4,395	1,106	5,501
19	2027	715,465	122,246	837,711	4,336	1,127	5,463
20	2028	719,738	123,399	843,137	4,273	1,153	5,426

Note 1: Number of 2009 electric meters includes approximately 51,100 installed in 2008.

In Year 5 (2013), 100% of the original meters being replaced are now replaced. Year 6 – Year 20 meter installations are new meters associated with growth.

Gas: The initial number of gas meters is also grown in the model based on annual meter growth rates shown in the next section. This results in the following Ohio gas module installations:

Year	Calendar Year	Number of Gas Meters with AMI			Modules Installed in the Specified Year		
		Residential	Commercial / Industrial	Total	Residential	Commercial / Industrial	Total
1	2009	80,401	6,644	87,045	80,401	6,644	87,045
2	2010	226,745	18,768	245,513	146,344	12,124	158,468
3	2011	376,009	31,077	407,086	149,264	12,309	161,573
4	2012	423,227	34,911	458,138	47,218	3,834	51,052
5	2013	440,388	36,251	476,639	17,161	1,340	18,501
6	2014	444,388	36,509	480,897	4,000	258	4,258
7	2015	448,316	36,761	485,077	3,928	252	4,180
8	2016	452,248	37,007	489,255	3,932	246	4,178
9	2017	456,138	37,248	493,386	3,890	241	4,131
10	2018	459,955	37,483	497,438	3,817	235	4,052
11	2019	463,686	37,712	501,398	3,731	229	3,960
12	2020	467,337	37,934	505,271	3,651	222	3,873
13	2021	470,938	38,145	509,083	3,601	211	3,812
14	2022	474,444	38,339	512,783	3,506	194	3,700
15	2023	477,884	38,529	516,413	3,440	190	3,630
16	2024	481,251	38,716	519,967	3,367	187	3,554
17	2025	484,572	38,900	523,472	3,321	184	3,505
18	2026	487,827	39,109	526,936	3,255	209	3,464
19	2027	491,015	39,342	530,357	3,188	233	3,421
20	2028	494,156	39,575	533,731	3,141	233	3,374

Note 1: Number of 2009 gas modules includes approximately 41,230 installed in 2008.

In Year 5 (2013), 100% of the original meters have been retrofitted with a module. Year 6 – Year 20 module installations are associated with new growth meters.

Service Territory Data

The following service territory data is used in the model for calculations regarding numbers of specific equipment, including distribution automation equipment.

Ohio Service Territory Data (2008)

Ohio Service Territory Component	Value	Growth Rate
Square Miles Covered	1,827.6	0.0%
Residential Electric Meters	619,544	Various (See Inputs)
Commercial/Industrial < 500kW Electric Meters	103,397	Various (See Inputs)
Residential Gas Meters	418,713	Various (See Inputs)
Commercial Gas Meters	34,802	Various (See Inputs)
Transformers	164,520	0.35%
Transformers / Sq Mile	90.0	N/A
Electric Meters / Transformer	4.4	N/A
Electric Meters / Sq Mile	395.6	N/A
All Meters / Sq Mile	643.7	N/A
Switching Capacitor Banks	2,127	0.25%
Substations	222	0.20%
Miles of Overhead Line	8,444.8	0.00%
Miles of Underground Line	3,977.7	0.65%
Number of Circuits	825	0.17%
LTCs/Voltage Regulators	1,041	0.17%
Circuit Breakers	812	0.17%
Electronic Reclosers	130	0.25%

Quantity of MMPs and Communications Equipment (2008 Data)

- Tollgrade MMPs (Line sensors) – 1.5 per distribution circuit mile (18,633)
- Tollgrade Aggregator – One required for every 40 Tollgrade MMPs (465)
- Communications for Electric Meters
  - Ambient Integrated Communications Box
    - Includes Echelon Data Collector, Verizon Modem, Power Supply, and other functionality
    - One for 80% of the transformers (131,616 of 164,520 transformers) – Serves 578,352 electric meters (76,776 are electric-only communications boxes, 54,840 are combination electric / gas communications boxes)
  - Commercial / Industrial < 500 kW Meters (103,397) – Contain integrated modem

- Data Collector/Modem Combination – One per each residential electric meter not being served by the Ambient Integrated Communications Box (41,192)

- Communications for Gas Meters with Module
  - Ambient Integrated Communications Box with Gas Data Collector
    - Includes Echelon Data Collector, Badger Gas Data Collector, Verizon Modem, Power Supply, and other functionality
    - One for 33% (one-third) of the transformers (54,840 of 164,520 transformers) – Serves 421,872 gas meters
  - Badger Gas Data Collector/Modem Combination – One per every 25 gas-only customers (1,266) (Gas-Only Customers: 23,039 residential, 8,604 commercial/industrial)
- Stand-Alone Modem on Capacitor Banks and Electronic Reclosers – One per device (2,257)

Equipment Details

Meters and Communications Equipment

The following meter and communications equipment makes up the modeled infrastructure:

Endpoints (Meters and MMPs)

Vendor	Equipment Type / Description	Order = 10,000 Modeled Cost	Order = 100,000 Modeled Cost	Order = 1,000,000 Modeled Cost	Useful Life	Failure Rate	Annual Operating Costs (per unit)	Annual Service Contract Costs (per unit)	Power Requirement (Watts)
Tollgrade	Tollgrade MMP	$ 500.00	$ 500.00	$ 500.00	9	2.0%		$ 0.60	5
Echelon	Residential Electric Meters	$ 141.50	$ 121.50	$ 107.50	20	0.3%		$ 1.00	2
????	Commercial Electric Meters (including integrated modem)	$ 450.00	$ 450.00	$ 450.00	20	0.3%		$ 1.00	2
Badger	Gas Module	$ 45.00	$ 45.00	$ 45.00	15	0.3%		$ -	0
American	Residential Gas Meters (250)	$ 48.88	N/A	N/A	20	0.3%		$ -	2
American	Commercial/Industrial Gas Meters (400)	$ 110.43	N/A	N/A	20	0.3%		$ -	2
American	Commercial/Industrial Gas Meters (1000)	$ 458.78	N/A	N/A	29	0.3%		$ -	2

Communications

Vendor	Equipment Type / Description	Order = 1,000 Modeled Cost	Order = 10,000 Modeled Cost	Order = 100,000 Modeled Cost	Useful Life	Failure Rate	Annual Operating Costs (per MB)[1,2]	Annual Service Contract Costs (per unit)	Power Requirement (Watts)
Tollgrade	Tollgrade Aggregator	$ 980	$ 980	$ 980	9	2.0%	$ 18		20
Ambient	Integrated Communications Box (electric only)			$ 500	10	2.0%	$ 18		5
Ambient / Badger	Integrated Communications Box (electric and gas)		$ 800	$ 800	10	2.0%	$ 18		5
Echelon / Verizon	Data Collector / Modem Combination (Residential electric meters not served by integrated communications box)			$ 220	10	2.0%	$ 18		5
Badger / Verizon	Data Collector / Modem Combination (Gas-only customers)	$ 500			10	2.0%	$ 18		5
Verizon	Modem (Distribution Equipment)	$ 350	$ 278	$ 250	10	2.0%	$ 18		5
Duke	Data Line at Substation						$ 2,640		5

Note 1: Annual operating costs are shown at full deployment rates; modeled at a higher, but decreasing rate per MB during deployment

Note 1: Annual operating costs for data line at substation is a flat rate from a modeling perspective and is independent of the amount of data (MB)

- In the model, meters are split between replacements (current meters) and new growth.
  - New growth electric meters are modeled at their incremental cost, the cost listed in the table above less $20 for residential meters and $110 for commercial meters
  - New growth gas meters are modeled the same as current gas meters as both will require the installation of the gas module. (It is assumed that new gas meters will **not** contain an integrated gas module.)
- Meter Base Replacements: It is estimated that 2.0% of existing Ohio meters replaced will also need a meter base replacement at an average cost of $656 ($115 materials, $75 inspection, and $466 labor)
- Gas Meter Replacements: It is estimated that 58,360 old "tin" meters will be replaced in order to become part of the SmartGrid project, as these old meters cannot be retrofitted with gas modules. The costs of these meters are listed in the table above. The number of each type of meter being installed is:
  - Meter Type 250: 38,000 meters
  - Meter Type 400: 14,500 meters
  - Meter Type 1000: 5,860 meters

Failure Rates

Failure rates in the above tables are used to determine equipment needs between installation and the end of the useful life.

- Equipment is modeled to be replaced at failure; i.e., the equipment will not be repaired either in the field or in the shops
- Failure rates are modeled as annual failure rates; i.e., failure rates are applied to total installed devices to determine the number of additional devices required for that year

Warranty Periods

Warranty periods are modeled for endpoint and communications equipment.

Vendor	Equipment Type / Description	Warranty Period
Tollgrade	Tollgrade MMP	1
Echelon	Residential Meters	3
????	Commercial Meters	3
Badger	Gas Module	3
American	Gas Meters	3
Tollgrade	Tollgrade Aggregator	1
Ambient	Integrated Communications Box (electric only)	1
Ambient / Badger	Integrated Communications Box (electric and gas)	1
Echelon / Verizon	Data Collector / Modem Combination (residential electric customers)	1
Badger / Verizon	Data Collector / Modem Combination (gas-only customers)	1
Verizon	Modem (Distribution Equipment)	1

- Warranties are materials only
- Equipment failing during the warranty period are modeled as failures with no materials cost and standard labor costs

Useful Life

Useful lives in the above tables are used to estimate replacement timing. (Failure costs are for equipment that has failed **during** the useful life. Replacement costs are for equipment that are being replaced **at the end of** the useful life)

- Useful lives were established using a combination of vendor estimates, current trends, and expert opinions
- From a modeling perspective, all equipment is replaced at the end of its useful life, taking into account that equipment failing before the end of its useful life has already been replaced and will not be replaced at the same time. This may overstate the replacement costs, if history is an accurate guide, as much of the equipment will last longer than its modeled useful life.

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Jan 09 2015

Duke Energy

SmartGrid Cost / Benefit Model – DE-Ohio

Modeled Installation Costs

The modeled installation costs for meters and communications equipment have been provided by both Duke Energy and vendors:

Source	Installation Task	Time Required (Hours)	Time Required (Minutes)	Hourly Rate	Cost Per Unit
Tollgrade	MMP Install	0.25	15.0	$ 62.50	$ 15.63
Tollgrade	Aggregator Install	0.50	30.0	$ 62.50	$ 31.25
Duke	Electric Meter Install	0.30	18.0	$ 59.93	$ 17.98
Duke	Gas Meter Install (250)	0.75	45.0	$ 89.00	$ 66.75
Duke	Gas Meter Install (400)	0.75	45.0	$ 80.00	$ 60.00
Duke	Gas Meter Install (1000)	3.00	180.0	$ 240.00	$ 720.00
Duke	Gas Module Install (Residential)	0.33	20.0	$ 60.75	$ 20.25
Duke	Gas Module Install (Commercial)	0.53	31.7	$ 60.75	$ 32.05
Duke	Meter Base Installation	4.00	240.0	$ 116.50	$ 466.00
Duke	Ambient Integrated Communications Box Install (with or without gas collector)	2.00	120.0	$ 79.21	$ 158.42
Duke	Data Collector / Modem Combination (Electric)	0.50	30.0	$ 79.21	$ 39.61
Duke	Data Collector / Modem Combination (Gas)	0.50	30.0	$ 79.21	$ 39.61
Duke	Modem (Distribution Equipment)	3.50	210.0	$ 69.06	$ 241.71

Other Capital Costs

- IT estimates a requirement for 70 FTEs (Duke Energy-wide), at a loaded rate of $100,000 per FTE, as a provision for turning-up the network and ensuring data from SmartGrid equipment is correctly integrated into the appropriate systems

Distribution Automation

Distribution automation includes replacing reclosers with circuit breakers, replacing relays in substations and circuit breakers, changing out the controls on capacitors and station LTCs/ regulators, sectionalization of the grid, and the implementation of self-healing technology.

Distribution Automation Category	Description (Ohio)	Cost per Unit	Total Initial Ohio Cost
Substation Communications	Upgrade 54 stations with RTUs / communications with SEL 351 capability	$ 90,000	$4,860,000 Labor: $3.6 million Materials: $1.2 million
Circuit Breakers	Replace 189 12 kV reclosers with circuit breakers (162 single-phase reclosers = 54 locations, 27 three-phase reclosers = 27 locations)	$ 80,000	$6,480,000 Labor: $4.9 million Materials: $1.6 million
Relays	Replace the relays in 343 12 kV switchgear feeder breakers	$ 30,000	$10,290,000 Labor: $7.7 million Materials: $2.6 million
	Replace the relays in 33 12 kV outdoor feeder breakers	$25,000 - $75,000	$1,045,000 Labor: $0.8 million Materials: $0.3 million
	Replace the relays in 25 34.5 kV outdoor feeder breakers	$30,000 - $40,000	$830,000 Labor: $0.6 million Materials: $0.2 million
Capacitors	Install communication functionality on 2,127 capacitor banks	$ 2,120	$4,509,240 Labor: $0.9 million Materials: $3.6 million
Regulators	Change out controls on 536 regulators (135 LTCs, 11 three-phase regulators, and 390 single-phase regulators)	$17,000 - $20,000	$4,655,000 Labor: $4.1 million Materials: $0.5 million
Sectionalization	Installation of reclosers (hydraulic and electronic) (estimated)	$8,000 - $20,000	$12,000,000 Labor: $7.5 million Materials: $4.5 million
Self-Healing Technology	Install Intelliteam on 4.0% of 764 circuits (covers 8.0% of the circuits) (Not all circuits are considered)	$ 180,000	$5,500,800 Labor: $1.8 million Materials: $3.7 million

- Costs for substation communications, circuit breakers, relays, and regulators are adjusted for planned upgrades. Planned upgrades are modeled as the estimated upgrade requirements spread evenly over 30 years. (This attempts to model the incremental costs of distribution automation upgrades.)

Information Technology

Initial Information Technology costs (to achieve benefits modeled) are estimated to be $119.34 million Duke Energy-wide based on an analysis by the IT Department. These costs by system are:

Systems	New/Enhancements	Hardware	Software	Duke Labor (hours)	Duke Labor Costs	Outside Consulting (hours)	Outside Consulting Costs	Total
Distribution Management System (DMS)	New	$3,000,000	$4,000,000	10,000	$1,000,000	18,000	$2,700,000	$10,700,000
Energy Data Management System (EDMS)	Enhancements	$750,000	$500,000	6,000	$600,000	8,000	$1,200,000	$3,050,000
Outage Management System (OMS)	Enhancements	$1,000,000	$1,000,000	8,000	$800,000	12,000	$1,800,000	$4,600,000
Misc Distribution Engineering Systems	New & Enhancements	$1,000,000	$500,000	4,000	$400,000	8,000	$1,200,000	$3,100,000
Asset Management System (EAM)	Enhancements	$1,000,000	$500,000	4,000	$400,000	10,000	$1,500,000	$3,400,000
Load Control Systems	New & Enhancements	$2,000,000	$1,000,000	8,000	$800,000	12,000	$1,800,000	$5,600,000
Work Management Systems	Enhancements	$1,000,000	$500,000	4,000	$400,000	10,000	$1,500,000	$3,400,000
GIS System	Enhancements	$1,000,000	$500,000	8,000	$800,000	8,000	$1,200,000	$3,500,000
AMI Systems - Electric Meters	New & Enhancements	$1,500,000	$2,000,000	8,000	$800,000	14,000	$2,100,000	$6,400,000
AMI Systems - Gas Meters	New & Enhancements	$1,000,000	$500,000	2,000	$200,000	6,000	$900,000	$2,600,000
Self Healing Systems	New	$1,000,000	$1,000,000	4,000	$400,000	8,000	$1,200,000	$3,600,000
Distribution Monitoring and Alerting Systems	New & Enhancements	$2,000,000	$1,000,000	8,000	$800,000	12,000	$1,800,000	$5,600,000
Other Distribution Head end Systems	New	$1,000,000	$750,000	8,000	$800,000	12,000	$1,800,000	$4,350,000
SCADA Systems	New & Enhancements	$1,000,000	$750,000	6,000	$600,000	8,000	$1,200,000	$3,550,000
PI System	Enhancements			4,000	$400,000	12,000	$1,800,000	$2,200,000
Customer Portal	New & Enhancements	$1,000,000	$1,000,000	8,000	$800,000	12,000	$1,800,000	$4,600,000
Customer Billing and Information System (CMS)	Enhancements	$1,000,000	$2,000,000	10,000	$1,000,000	24,000	$3,600,000	$7,600,000
Customer Billing and Information System (CBIS)	Enhancements	$1,000,000	$2,000,000	10,000	$1,000,000	24,000	$3,600,000	$7,600,000
Net Metering Application	New	$1,000,000	$1,000,000	6,000	$600,000	10,000	$1,500,000	$4,100,000
Data Hubs/Data Warehouse	New	$1,000,000	$1,000,000	8,000	$800,000	14,000	$2,100,000	$4,900,000
IBM Websphere MQ Messaging Bus	Enhancements	$1,000,000	$1,000,000	6,000	$600,000	16,000	$2,400,000	$5,000,000
Sub Total		$24,250,000	$22,500,000	140,000	$14,000,000	258,000	$38,700,000	**$99,450,000**
Contingency (20%)		$4,850,000	$4,500,000	28,000	$2,800,000	51,600	$7,740,000	$19,890,000
Total		***$29,100,000***	***$27,000,000***	***168,000***	***$16,800,000***	***309,600***	***$46,440,000***	***$119,340,000***

- Duke Energy labor rate is $100 per hour
- Outside consulting labor rate is $150 per hour

Duke Energy

SmartGrid Cost / Benefit Model – DE-Ohio

- As per the Shared Services Company Agreement, IT costs are spread across jurisdictions based on the relative number of customers in each jurisdiction

	Number of Customers		
Jurisdiction	Electric	Gas	Total
Indiana	773,954	-	773,954
Ohio	686,578	423,570	1,110,148
Kentucky	133,868	94,782	228,650
Total Midwest	1,594,400	518,352	2,112,752
North Carolina	1,800,000	-	1,800,000
South Carolina	500,000	-	500,000
Total Carolinas	2,300,000	-	2,300,000
Total Duke	3,894,400	518,352	4,412,752

- IT Capital Costs after the initial five-year implementation are calculated as a percentage (10%) of the initial IT Capital Costs
- Based on the analysis on the previous page, IT costs are split among cost categories by the following percentages:

IT Cost Category	Percentage of Total IT Capital Costs
Hardware	24%
Software	23%
Duke Labor	14%
Outside Consulting	39%

- IT has estimated the amount of O&M required for the new systems and enhancements based upon historical analysis of system maintenance. The following percentages are applied to cumulative IT capital investment:

IT Cost Category	O&M Percentages
Hardware	15%
Software	18%
Duke Labor	20%
Outside Consulting	20%

Project Management Office

The Project Management Office, or PMO, captures the labor costs associated with managing the deployment of SmartGrid, from both a designing and planning point of view and a deployment point of view. These costs are considered capital costs. These costs do not include the costs of actually installing equipment in the field or designing and installing IT systems / enhancements.

Duke Energy-Wide Annual PMO Costs

Category of FTE	Number of FTEs	Average Salary	Loading Rate	Annual Consulting Hours	Average Hourly Rate	Consulting Fees (per consultant)	Expenses (per consultant)	Total
Duke Employees - Planning	14	$ 87,500	45.0%					$ 1,776,250
Duke Employees - Power Delivery	25	$ 87,500	45.0%					$ 3,171,875
PD - Contract Field Supervisors	6	$ 120,000	0.0%					$ 720,000
Consultants - Planning	7			1,768	$ 200.00	$ 353,600	$ 53,040	$ 2,848,480
Consultants - Power Delivery	3			1,768	$ 200.00	$ 353,600	$ 53,040	$ 1,219,920
Total	55							$ 9,734,525

Note: Average Salary – Represents the average salary of Band L and M: $75,000 - $100,000

The PMO costs are then allocated to jurisdictions based on the relative percentage of customers (as detailed in the previous Information Technology section). Additionally, the PMO is expected to ramp up in 2008 and start ramping down in 2013, as detailed in the following table:

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
	2008	2009	2010	2011	2012	2013	2014	2015
PMO Staffing Level	30%	100%	100%	100%	100%	50%	10%	0%
Duke-wide PMO Costs	$ 3,025,490	$ 10,448,027	$ 10,761,468	$ 11,084,312	$ 11,416,841	$ 5,879,673	$ 1,211,213	$ -
Ohio PMO Costs	$ 762,639	$ 2,633,647	$ 2,712,656	$ 2,794,036	$ 2,877,857	$ 1,482,096	$ 305,312	$ -

O&M Costs (Operating & Maintenance)

O&M costs in the model are made up of:

- New equipment operating costs, including service contract rates and maintenance fees, data transfer fees, and costs associated with the power required by the new equipment
- Additional FTEs required for disposing of the large quantity of electro-mechanical meters and for sample testing of a large quantity of new meters and other equipment (Only during deployment)
- Additional FTEs for investigating power theft
- IT O&M costs
- Customer Service O&M costs associated with addressing the new meters and their data and how they are tied to the billing system (Only during deployment)
- O&M labor associated with new equipment installed in the field, including the new communications equipment and new distribution automation equipment, but excluding meters. (Specific Field labor for O&M on new meters is excluded since meters and associated O&M exist today and reductions in these costs due to new, more-advanced meters are captured under benefits.)

Data Transfer Costs

- The "half-year convention" is used for the first year to account for deployment timing
- Verizon Modem costs: A sliding scale is used based upon the total Duke Energy-wide system monthly data transfer quantities. Based upon projected Duke Energy-wide data requirements, the monthly costs are $3.00 per MB in 2009, $2.25 per MB in 2010, $2.00 per MB in 2011, $1.75 per MB in 2012, and $1.50 per MB from 2013-2028.
- Electric meters are modeled at 100 KB per month based upon vendor studies and current pilot results
  - Assumption: This data size suffices for monthly data reads for billing purposes, test bed baseline for load profiles and/or energy efficiency needs (5,000 meters), and other modeled benefits, such as outage investigation and detection.
  - Future direct load control / demand response data requirements may increase the per meter data quantities required to provide full functionality.

- In Ohio, 100 KB per meter translates into 70 KB per residential meter and 280 KB per commercial / industrial meter < 500 kW

- Gas meters are modeled at 5 KB per month based upon the need for a single meter read (total quantity / MCf) per month
- Distribution equipment (capacitors and reclosers) are modeled at 10 MB per month
- Tollgrade aggregators are modeled at 5 MB per month
- Substation Communications: $220 per month per data line for 54 retrofitted substations

Other Equipment O&M Costs

- Ambient Integrated Communication Box: Annual software maintenance fee per box; currently modeled on a sliding scale of $11.25 in 2008 to $6.00 in 2013 and beyond
- New Equipment Power Costs ("half-year convention" is used for the first year) – Each piece of equipments' power requirements and the average electricity price (fuel only) are used to calculate power costs
- Ongoing Equipment O&M: Calculated as a percentage (1%) of total invested capital costs for distribution automation and communications equipment.

IT O&M Costs (Duke Energy-wide)

- IT Network Infrastructure O&M Costs
  - Maintenance for Management Tools (materials): Duke Energy-wide costs of $100,000 in 2009 to $200,000 in 2013. Allocated to DE-Ohio based on DE-Ohio's numbers of customers as a percentage of total Duke Energy customers.
  - Maintenance for Central Network (materials): Duke Energy-wide costs of $125,000 in 2009 to $225,000 in 2013. Allocated to DE-Ohio based on DE-Ohio's numbers of customers as a percentage of total Duke Energy customers.

- Network Infrastructure Support Labor: Duke Energy-wide estimate of 40 FTEs at annual cost of $100,000 per FTE. These FTEs take over the network infrastructure maintenance from the 70 FTEs mentioned earlier; i.e., the year of installation is considered capital and the following years are considered O&M. Allocated to DE-Ohio based on:
  - Number of new meters / modules deployed as a percentage of new meters / modules deployed in all of Duke Energy jurisdictions – During deployment (Years 2009-2013)
  - DE-Ohio's numbers of customers as a percentage of total Duke Energy customers – After deployment (Years 2014-2028)

- Ongoing IT Back-Office O&M Costs: IT has estimated the amount of O&M required for the new systems and enhancements based upon historical analysis of system maintenance. The following percentages are applied to cumulative IT capital investment:

IT Cost Category	O&M Percentages
Hardware	15%
Software	18%
Duke Labor	20%
Outside Consulting	20%

Additional O&M Costs

- Customer Service O&M to Address New Meters / Set-Up With Billing: Estimated at seven minutes per meter for hourly FTEs with supervisory personnel estimated at a ratio of one supervisor per nine hourly FTEs. (Only during deployment)

	Year 1	Year 2	Year 3	Year 4	Year 5
	2009	2010	2011	2012	2013
Hourly Call Center Workers Needed	12.64	25.26	25.77	7.65	3.27
Call Center Supervisors Needed	1.40	2.81	2.86	0.85	0.36

- Meter Disposal FTEs: The requirement for additional FTEs to assist in disposing of meters during the deployment period

	Year 1 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013
Number of FTEs (Minimum) - Meter Disposal	3	3	1	1	1
Number of FTEs (Maximum) - Meter Disposal	5	5	2	1	1

- Meter Testing FTEs: The requirement for additional FTEs to assist in sample testing new meters / modules

	Year 1 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013
Number of FTEs (Minimum) - Meter Testing	2.00	2.00	1.00	0.25	0.05
Number of FTEs (Maximum) - Meter Testing	2.00	2.00	1.00	0.25	0.05

- Power Theft FTEs: The additional data provided by the SmartGrid project will enable the detection of additional power theft. FTEs are required to investigate these instances and to achieve the benefits modeled. In Ohio, it is estimated that 4.5 FTEs will be required.

Useful Lives and Depreciation Lives

There was considerable discussion concerning the useful lives of the new equipment and the corresponding depreciation lives, both from a book and a tax perspective. Taken into consideration were expected lives of new equipment provided by vendors, historical trends and experiences with like equipment, current book depreciation and tax depreciation schedules, and projected legislation affecting smart grid equipment depreciation. Book depreciation lives were assumed to correspond to the forecasted useful lives.

Equipment Type	Vendor	Model Description	Useful Life (Years)	Depreciation Life in the Model (Years)	
				Book	Tax (MACRS)
Endpoint	Tollgrade	Tollgrade MMP	9	9	20
Endpoint	Echelon	Residential Electric Meters	20	20	20
Endpoint	???	Commercial/Industrial < 500 kW Electric Meters	20	20	20
Endpoint	American	Residential Gas Meters	20	20	20
Endpoint	American	Commercial/Industrial Gas Meters	20	20	20
Endpoint	Badger	Gas Module	15	15	20
Communication	Tollgrade	Tollgrade Aggregator	9	9	20
Communication	Ambient	Integrated Communications Box (Electric Only)	10	10	20
Communication	Ambient / Badger	Integrated Communications Box (Electric & Gas)	10	10	20
Communication	Echelon / Verizon	Data Collector/Modem Combination (Stand-Alone Residential Meter)	10	10	20
Communication	Badger / Verizon	Data Collector/Modem Combination (Gas-Only Customers)	10	10	20
Communication	Verizon	Modem on Distribution System	10	10	20
Distribution	Duke	Substation RTUs/Comms with SEL 351 Capability	20	20	20
Distribution	Duke	Circuit Breakers (replacing 189 12-kV reclosers with breakers)	30	30	20
Distribution	Duke	Circuit Breaker Relays (replacing relays in 401 feeder circuit breakers)	20	20	20
Distribution	Duke	Controls on Capacitors	30	30	20
Distribution	Duke	Controls on LTCs/Regulators	30	30	20
Distribution	Duke	Sectionalization (installation of reclosers - hydraulic and electronic)	30	30	20
Distribution	Duke	Self-Healing (installation of Intelliteam)	30	30	20
IT	Various	Software, including Duke Labor and Outside Consulting	5	5	3
IT	Various	Hardware	8	8	5
Labor	Various	Labor for Set-up and Install	As per equipment	As per equipment	As per equipment
Labor	Various	Project Management Office (PMO)	N/A	Weighted Average: 13.887	Weighted Average: 20

Inflation Rates

Annual inflation rates were applied to primarily labor costs in the cost and benefit calculations.

Item	Inflation Rate
Labor	3.6% (2008-2009), then 3.0%
Materials	2.3% (2008-2009), then 3.0%
Blended (Labor / Materials)	3.0%

Inflation Exceptions

- Inflation is not applied to data transfer fees: Inflation is assumed to be included in the initial contract pricing (five years) and, for years six through twenty, data transfer fees are forecasted to remain flat based upon historical pricing trends
- Inflation is not applied to Ambient integrated communication box maintenance fees: Inflation is assumed to be included in the initial contract pricing (five years) and, for years six through twenty, software maintenance fees are forecasted to remain flat based upon historical pricing trends
- Inflation is not applied to residential and commercial/industrial < 500 kW electric meters, residential and commercial/industrial gas meters, or gas modules: Inflation is assumed to be included in the initial contract pricing (five years) and, for years six through twenty, meter costs are expected to remain flat based on current meter pricing trends (decreasing) offset by delivery cost increases
- Inflation is not applied to communications equipment costs: Inflation is assumed to be included in the initial contract pricing (five years) and, for years six through twenty, communication costs are expected to remain flat or decrease based on the current focus on developing smart grid communications technology and the relative early stage at which development currently exists
- Inflation is not applied to IT Back-Office O&M (Software and Hardware categories): Inflation is assumed to be included in the initial contract pricing (five years) and, for years six through twenty, technology maintenance fees are forecasted to remain flat based upon historical pricing trends

Growth Rates

Growth rates were applied to the price of electricity and gas, the amount of energy consumed, and the number of installed meters:

Year	Ohio Growth Rates					
	Electric Rate Price	Residential Electric (MWh)	Commercial Electric (MWh)	Gas Rate Price	Residential Gas (MCf)	Commercial Gas (MCf)
2008	7.78%	0.00%	0.00%	-1.88%	0.00%	0.00%
2009	-5.68%	-0.04%	0.87%	-1.51%	-0.53%	1.63%
2010	7.31%	1.88%	1.58%	1.65%	0.19%	0.19%
2011	-6.49%	-1.99%	0.76%	2.81%	0.26%	0.48%
2012	3.91%	-2.07%	0.68%	2.84%	0.12%	0.26%
2013	2.30%	-2.15%	0.65%	2.85%	0.31%	0.47%
2014	2.30%	-0.06%	0.98%	2.59%	0.31%	0.51%
2015	2.28%	0.04%	0.99%	2.86%	0.35%	0.46%
2016	2.23%	0.00%	0.98%	2.86%	0.42%	0.46%
2017	2.22%	-0.15%	0.97%	2.85%	0.44%	0.43%
2018	2.23%	-0.30%	0.94%	2.85%	0.48%	0.42%
2019	2.23%	-0.33%	0.92%	2.91%	0.50%	0.39%
2020	2.22%	0.13%	0.97%	2.93%	0.51%	0.36%
2021	2.24%	0.10%	0.99%	3.66%	0.50%	0.31%
2022	2.27%	0.05%	0.99%	3.66%	0.50%	0.28%
2023	2.27%	0.05%	0.97%	3.66%	0.50%	0.28%
2024	2.27%	0.01%	0.92%	3.68%	0.51%	0.28%
2025	2.27%	0.02%	0.85%	3.67%	0.53%	0.28%
2026	2.28%	0.01%	0.84%	1.89%	0.53%	0.42%
2027	2.27%	-0.03%	0.84%	1.90%	0.44%	0.63%
2028	2.27%	-0.10%	0.81%	1.90%	0.60%	0.70%

Year	Ohio Meter Growth Rates			
	Residential Electric Meters	Commercial / Industrial <500 kW Electric Meters	Residential Gas Meters	Commercial / Industrial Gas Meters
2008	0.00%	0.00%	0.00%	0.00%
2009	1.01%	0.90%	1.06%	0.48%
2010	0.93%	0.89%	1.10%	1.27%
2011	0.87%	0.85%	1.02%	0.87%
2012	0.85%	0.85%	0.95%	0.76%
2013	0.83%	0.87%	0.93%	0.72%
2014	0.81%	0.87%	0.91%	0.71%
2015	0.81%	0.87%	0.88%	0.69%
2016	0.80%	0.87%	0.88%	0.67%
2017	0.78%	0.87%	0.86%	0.65%
2018	0.75%	0.87%	0.84%	0.63%
2019	0.74%	0.87%	0.81%	0.61%
2020	0.72%	0.89%	0.79%	0.59%
2021	0.70%	0.89%	0.77%	0.56%
2022	0.68%	0.90%	0.74%	0.51%
2023	0.67%	0.90%	0.73%	0.50%
2024	0.65%	0.91%	0.70%	0.49%
2025	0.64%	0.91%	0.69%	0.48%
2026	0.62%	0.92%	0.67%	0.54%
2027	0.61%	0.93%	0.65%	0.60%
2028	0.60%	0.94%	0.64%	0.59%

Other Financial Assumptions / Inputs

Labor Loading Rates

Employee	Labor Loading Rate
Labor Loading Costs (Midwest company average rate for union employees)	39.50%
Labor Loading Costs (Midwest company average rate for non-union employees)	42.00%
Labor Loading Costs (CG&E employees)	52.54%
Average Duke Labor Loading Costs	45.00%

Tax Rates

Tax	Tax Rate
Federal income tax rate	35.00%
State income tax rate (business income)	0.00%
City or local income tax rate	0.35%
Property tax rate - Electric	8.0105%
Assessed value rate - Electric Distribution (Property Tax)	88.00%
Assessed value rate - Electric Communications (Property Tax)	24.00%
Property tax rate - Gas	8.8585%
Assessed value rate - Gas Distribution (Property Tax)	25.00%
Assessed value rate - Gas Communications (Property Tax)	25.00%
Ohio sales tax rate (Exempt Items)	0.00%
Ohio sales tax rate (Taxable Items)	6.50%

- **All Benefits listed as Avoided Costs (see Benefits section) are excluded from the tax calculations**
- Property Tax is calculated based on capital dollars invested and unique property tax depreciation tables
  - There is a floor of 15% of capital spent
- Ohio sales tax is applied to only **capital IT hardware materials** purchases; all other capital expenditures modeled are exempt from Ohio sales tax. (Capital IT hardware is assumed to be located in Ohio – a conservative approach at this time as some or all of the hardware could be located in states other than Ohio.)

Revenues

Revenue Category	Ohio Revenue (2008 estimate)
Residential electric revenue (exclusive of fuel)	$ 299,713,000
Commercial electric revenue (exclusive of fuel)	$ 176,022,000
Residential electric revenue (inclusive of fuel and trackers)	$ 299,713,000
Commercial electric revenue (inclusive of fuel and trackers)	$ 176,022,000
Residential gas revenue (exclusive of fuel)	$ 125,135,709
Commercial gas revenue (exclusive of fuel)	$ 40,825,026
Residential gas revenue (inclusive of fuel)	$ 379,426,397
Commercial gas revenue (inclusive of fuel)	$ 143,009,833
Residential electric revenue (generation) (exclusive of fuel)	$ 281,721,000
Commercial electric revenue (generation) (exclusive of fuel)	$ 261,419,000
Residential electric revenue (generation) (inclusive of fuel and trackers)	$ 447,248,000
Commercial electric revenue (generation) (inclusive of fuel and trackers)	$ 396,028,000

Other Rates / Assumptions

- Debt Rate - 6.45%
- Percent Equity Financed – 50%
- Discount Rate – 7.59625%
- Electricity rates
  - Weighted Average: \$.0878/kWh
  - Weighted Average (fuel only): \$.0281/kWh
  - Weighted Average (excluding fuel): \$.0597/kWh
- Average hourly power consumption (electric) – 3.4457 kWh
- Assumption: Existing meters will continue to be depreciated on their current schedule through a Reg Asset; thus, there is no marginal impact on the ratepayer for depreciation of existing meters removed from service. **This depreciation does not appear in the model:**
  - Electric: \$2.09 million annually for 27.8 years = \$57.97 million
  - Gas Meters: \$0.80 million annually for 33.4 years = \$26.71 million
  - Gas Meter Installations: \$0.61 million annually for 28.7 years = \$17.43 million
- Existing inventory of meters in Ohio is not addressed in the model directly
  - It is assumed that any electro-mechanical meters still existing upon completion of implementation will be depreciated as all other removed meters; i.e., as per the current depreciation schedule
  - A conservative view is taken with regards to scrap value of the remaining inventory in that it is assumed the inventory is worked down over the five years of implementation and no meters remain to be scrapped
- Assumption: Reconnect fees may or may not be charged or reduced when reconnect capability is automated. A reduction in these fees is currently excluded from the model until a specific decision on these fees is made.

- Corporate allocations are not included in the model
- Though all FTE costs in the model are costs to the project, they may not necessarily be new costs to Duke Energy overall; e.g., Project Management Office costs include people who are current Duke Energy employees. This is important in using the modeled data to understand and/or model rate impacts.

Benefits

- Benefits are grouped into five major areas:
  - Metering
  - Outage
  - Distribution
  - Other – Customer Service, Billing, and Safety
  - Customer / Societal Benefits
- Additionally, benefits are placed into one of four savings categories:

Savings Category	Description
Direct Expense Reductions	Savings associated with actual costs removed from the budget, primarily associated with removing FTEs or removing workload from FTEs (reducing overtime)
Increased Revenue	Increased revenue into the company whether from selling/salvaging the large number of meters that have been removed, charging for specific products and services, or incremental investment income associated with having receivables in earlier (cost of money)
Operational Efficiency	These are generally operational improvements that result in specific time savings. This increase in efficiency is translated into a dollar cost savings using FTE costs, but doesn't fall into the Hard Cost Savings because it is not predicted to result in the removal of FTEs. The "savings" is reinvested in the company by allowing employees to perform additional value-added work that would otherwise go undone. These costs are often referred to as "soft cost savings."
Avoided Costs	These are savings associated with avoiding expenditures in the future, primarily capital expenditures, that are projected to be present in later years. An example would be costs of capital investment for new generation that can be avoided by implementing voltage reduction strategies, system fine-tuning, or DSM policies / programs (DSM benefits are not currently captured in the model). Another example would be the capital anticipated to replace electro-mechanical meters. This should also include any working capital savings as a result of deferred, rather than avoided, future CapEx investments.

- Except for tax calculations, benefits are treating equally in the financial model regardless of their savings category. **This would not be the case in a revenue recovery / rates model.**
- Benefits are allocated based on deployment rates; lagging one year to account for the timing of equipment deployment

Metering

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Metering	Eliminate regular meter reads	SmartGrid technology would eliminate on-cycle manual meter reading and associated costs. The benefit value includes a reduction in all direct meter reading labor expense, including Duke labor and transportation.	Direct Expense Reductions	• Annual electric meter reading (Duke) - $3,961,788 • Annual gas meter reading (Duke) - $3,097,216 • FTEs - 200 • Annual number of meter reads per meter - 12 • Meter reading costs eliminated - 90%	Year 2
Metering	Reduce off-cycle / off-season reads (Allows establishment, transfer, and/or termination of utility service)	Because SmartGrid technology can provide daily and on-demand reads, follow-up costs related to meter checks and re-reads can be reduced (connect/disconnect, move-in/move-out, billing exceptions, etc). • Incorporation of automated phone/text data messaging will allow customer alerts via email, voicemail, or text message directly before and/or after service has been initiated, transferred, or terminated. • Real-time or near real-time data feeds will ensure that customer will likely realize decreased arrearages. Automatic disconnect/reconnect capabilities will greatly benefit customers by providing more timely disconnections for nonpayment and reconnections, as disconnections will be more accurately aligned with regulatorily-required disconnection notifications. Reconnections may also be achieved 7 days a week/24 hours a day.	Direct Expense Reductions	• Electric Meter Order Costs - $3,366,005 • Electric Meter Order Costs Eliminated - 70% C&I; 90% Residential • Electric Non-Pay Disconnect Costs - $1,453,983 • Electric Non-Pay Disconnect Costs Eliminated - 80% • Gas Meter Order Costs - $2,823,035 • Gas Meter Order Costs Eliminated - 70% C&I; 90% Residential • Gas Non-Pay Disconnect Costs - $1,454,291 • Gas Non-Pay Disconnect Costs Eliminated - 0% • Reconnect Fees are not currently modeled	Year 2
Metering	Reduce single-call dispatches through remote diagnostics (for individual customer events)	With real-time voltage sensing capability, SmartGrid technology can provide system dispatchers with the ability to reduce unnecessary single-call trouble dispatches that are due to issues that can be isolated on the customer's side of meter. A reduction in the number of calls translates into a reduction in the overall number of personnel needed to respond to these calls.	Direct Expense Reductions	• Single Customer, Non-Storm Event Costs - $4,161,649 • Expected percent reduction - 15%	Year 2
Metering	Reduction in power theft resulting in increased revenue	Energy theft in the United States is a billion dollar business, and by many accounts, represents between .5% and 1% of any utility's overall revenue. A mass or large-scale SmartGrid deployment can be used as an effective tool to monitor and track consumption registration on meters for increased revenue / lower losses due to theft.	Increased Revenue	• Electric revenue • Percent estimated theft - 1% • Estimated reduction in power theft - 50% • Estimated collection rate - 45%	Year 2
Metering	Power theft - Decreased theft recovery budget	Energy theft in the United States is a billion dollar business, and by many accounts, represents between .5% and 1% of any utility's overall revenue. A mass or large-scale SmartGrid deployment can be used as an effective tool to monitor and track consumption registration on meters for increased revenue / lower losses due to theft and decreased budget to pursue and remediate theft.	Direct Expense Reductions	None modeled at this time (Increase modeled in O&M Costs)	Year 2

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Metering	Meter operations - Avoided capital costs associated with replacing old meters and handheld meter reading equipment	Deployment of SmartGrid technology would defer the capital costs associated with replacement of meters and other manual meter reading equipment (e.g., handheld equipment) that otherwise would have been required. It is offset by costs already budgeted to replace existing meter stock, especially where solid state meters are targeted to replace electromechanical meters in the field.	Avoided Costs	• Annual capital for new meter purchase (materials) - $877,427 • Annual capital for new meter purchase (labor) - $845,264 • Hand-held equipment purchase (one-time) - $65,000	Year 2
Metering	Meter operations - Decrease annual expenses of repairing and testing electro-mechanical meters	Deployment of SmartGrid technology would decrease the annual cost of repairing and testing electro-mechanical meters and manual meter reading equipment, but would be offset by any new costs for maintenance associated with the newer metering and communications technology.	Direct Expense Reductions	• Annual cost of repairing meters - $156,395; Expected reduction - 86% of repair costs • Annual cost of testing meters - $126,332; Expected reduction - 76% of testing costs • Annual cost of handheld meter reading equipment maintenance - $175,000; Expected reduction - 81% of maintenance costs	Year 2
Metering	Increased revenue associated with meter accuracy improvement	Evidence shows that electro-mechanical meters, on average, tend to slow with age due to wearing of moving parts. Solid-state meters do not have moving parts and, therefore, are generally accepted to perform at 100% accuracy for their expected service life. These meters can improve the average system meter accuracy not only because of the absence of mechanical failures but because deviations from expectations should be greater and can be rectified sooner. Greater accuracy translates into greater revenue assuming that the vast majority of inaccuracies are slowing down of meters. (Since this is dependent upon the specific recovery (e.g., tariff) process for a utility, the actual increased revenue be short-term in nature; i.e., until the next tariff or rate case adjustment occurs. After the rate case adjustment, there will continue to be savings as compared to the current day situation.) The revenue increase would also be offset by any increases in customer service costs (e.g., call center contacts) as a result of customer inquiries for higher billing charges for significant variances in meter accuracy.	Increased Revenue	• Percent accuracy improvement (.03%) • Residential electric revenue	Year 2
Metering	Increased revenue from salvaging the electro-mechanical meters	Existing meters in service will be replaced. Due to the current over supply in the used electro-mechanical meter market, salvaging the meters is the primary option. Salvaging meters will result in increased revenue, but would be offset by the accelerated write-down in undepreciated value from the balance sheet. The benefit is applicable to both old meters and failed new meters that are outside the warranty window	Increased Revenue	• Number of meters replaced • Salvage / scrap value per meter - $1.25	Year 2

Outage

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Outage	Outage Assessment Reduction (Electric) - Reduce time to verify which customers have been restored and which remain out.	During isolated and/or major storms, it is critical to determine which customers have been restored, as well as the customers who are still experiencing an outage. SmartGrid communications system can be used to query individual meters (or meter status reports) to achieve a level of knowledge about power outage status. This capability could be utilized along with other SmartGrid-related data to reduce the time to support restoration activities (verifying outages remaining and those already repaired, etc). This benefit relates to the work of the outage assessors.	Direct Expense Reductions	• Number of Outages • Outage Duration • Number of Assessors • % of Outage Spent in Assessment (Assessors) - 65% • Reduction in Assessment Time - 20% (Applies to Storm Levels 2, 3, and 4)	Year 3
Outage	Outage Crew Time Reduction (Electric) - Reduce time to verify which customers have been restored and which remain out.	During isolated and/or major storms, it is critical to determine which customers have been restored, as well as the customers who are still experiencing an outage. SmartGrid communications system can be used to query individual meters (or meter status reports) to achieve a level of knowledge about power outage status. This capability could be utilized along with other SmartGrid-related data to reduce the time to support restoration activities (verifying outages remaining and those already repaired, crew time in knowing where to go next, etc). This benefit relates to the work of the outage crews.	Direct Expense Reductions	• Number of Outages • Outage Duration • Number of Crew Members • Reduction in Crew Time - 10% (Level 2, 3, and 4), 15% (Level 1) (Applies to Storm Levels 1, 2, 3, and 4)	Year 3
Outage	Outage Crew Time Reduction (Electric) - Reduce time to identify / verify information regarding OCB / recloser failures	During OCB / recloser failures, it is critical for maintenance crews / outage crews to quickly identify / verify failure locations, as well as verify repairs. The availability of data from these pieces of equipment as a result of installed relays enables this benefit.	Direct Expense Reductions	• Number of Outages • Outage Duration • Number of Crew Members • Reduction in Crew Time - 20% (Applies to OCB/Recloser Failures)	Year 3
Outage	Outage - Incremental revenue associated with faster restoration (Electric)	SmartGrid'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.	Increased Revenue	• Number of Outages • Outage Duration • Number of Customers Affected • % of Outage in Assessment • Reduction in Assessment Time • Avg. Customer Hourly Power Consumption • Weighted Average Electricity Rate (Applies to Storm Levels 2, 3, and 4)	Year 3

Distribution

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Distribution	System Voltage Control - Reduction in demand (Energy, Capacity, CO_2)	Improved voltage control enables more efficient distribution of power (e.g., reduced line losses) - which 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 to service the load). Improved performance in system voltage control enables the avoidance/deferral of capital expenditures related to the distribution peak load and expected reduction in demand (.5%). This benefit is also known as the "voltage reduction strategy," whereby it is estimated that Duke can lower voltage by 2% full time (in addition to the peak reduction) which corresponds to a 1% load reduction full time. This scenario is modeled by the DSMore software package (simulates the Ohio load situation (supply and demand) using actual load, supply, and weather data) and the results are entered into this model. Benefits include avoided energy, avoided capacity, and avoided CO_2.	Avoided Costs	• Data from DSMore software • Distribution Peak Load - 3600 MW	Year 4
Distribution	Power Shortage Voltage Reduction - Reduction in demand (Capacity)	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 - which results in the need for less capital investment for handling peak loads and improved operating expenses during peak load conditions. Improved performance in power shortage voltage control reduction enables the avoidance/deferral of capital expenditures related to the distribution peak load and expected reduction in demand (5%) for the 2% probability of occurrence. This scenario is modeled by the DSMore software package (simulates the Ohio load situation (supply and demand) using actual load, supply, and weather data) and the results are entered into this model. (Same as System Voltage Control expect that the voltage is outside the allowed range. This is used in emergency situations.)	Avoided Costs	• Data from DSMore software • Distribution Peak Load - 3600 MW	Year 4
Distribution	Reduction in the number of FTEs performing continuous voltage monitoring	Improved capability in automated monitoring of voltage for low voltage situations allows for a major reduction in the time spent currently performing this function by dedicated FTEs. This also improves customer service by proactively catching voltage problems prior to customer complaints. (Returning voltage values from customer meters. Communications will enable immediate knowledge when we have a voltage problem. This will help root cause diagnosis from in timeliness and man power to set up monitoring equipment.)	Direct Expense Reductions	• Number of FTEs checking low voltage issues - 2 • Cost per FTE - $121,000 • Expected % Reduction - 80%	Year 2
Distribution	VAR Management - Reduction in demand (Capacity)	Improved performance in VAR management enables the avoidance/deferral of capital expenditures related to the VAR factor and percentage of capacitors offline. Translated into a dollar figure by factoring in the plant carrying cost of $72.36/kW. (Capacitor banks are used to control VARs, high percentage are failed (%10-20) at peak load and we do not know it. Duke Energy presently check them twice a year. A blown fuse is an example of the failure. Control will allow remote failure to be observed. Communications will allow near 100% functionality.)	Avoided Costs	• VAR Factor - 0.6 • % of Capacitors Offline - 15% • Distribution Peak Load - 3600 MW • Carrying Cost of a Plant - $72.36 / kW	Year 2

Duke Energy

SmartGrid Cost / Benefit Model – DE-Ohio

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Distribution	Reduction in CapEx through improved asset management	Avoided/deferred capital cost savings by improving asset utilization - enabled by more detailed and accurate system planning using more comprehensive operating datasets. Availability of better planning and optimized data improves asset management which enables a 2% reduction in the relevant capital expenditure budget. (Results in reduction of capital management for load growth projects, lower man-hours for load research, deferral of transformers, etc.)	Avoided Costs	• Relevant portion of CapEx Budget - $35,000,000 • % CapEx Budget Reduction due to availability of better data, optimized planning, etc. - 2%	Year 2
Distribution	Reduced maintenance costs associated with capacitor inspections	Hard cost savings from reduced maintenance costs enable by condition-based maintenance practices (i.e., maintaining the equipment based upon its known actual operating conditions, as compared to time-based, reactive, or proactive maintenance practices. (Providing automated communications of capacitor operating information allows for a reduction in the number of manual inspections performed on the capacitors.) It may also result in the ability to reduce the total number of cap banks on the system, if greater utilization is increased overall, thus reducing future CapEx and OpEx expenditures. (Eliminate the inspections for the VAR management.)	Direct Expense Reductions	• Number of Capacitors • Avg # of Hours to Inspect - 1.5 • Hourly Labor Rate - $58.13 • % of Inspections Eliminated - 80%	Year 2
Distribution	Reduced maintenance costs associated with circuit breaker inspections	Hard cost savings associated with replacement of the 189 12-kV reclosers with new vacuum breakers. The benefit is a reduction in both internal inspections and external inspections	Direct Expense Reductions	• Annual cost savings - $79,900	Year 2
Distribution	Reduced line losses through system fine-tuning (Energy, Capacity, CO2)	Fine tuning enables more efficient distribution of power (e.g., reduced line losses in the distribution grid, prior to the secondary or the transformer) - which 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. This scenario is modeled by the DSMore software package (simulates the Ohio load situation (supply and demand) using actual load, supply, and weather data) and the results are entered into this model. Benefits include avoided energy, avoided capacity, and avoided CO_2. (Precise information from customer meters regarding loads (the value of the unique load at the end of each feeder not just the value at the substation) is used to fine-tune the system and decrease line losses.)	Avoided Costs	• Data from DSMore software • Distribution Peak Load - 3600 MW • Expected Losses in the distribution grid (prior to the secondary or the transformer) - 1% • Expected performance improvement - 10%	Year 2

Other – Customer Service, Billing, and Safety

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Other	Call center efficiency - Decreased call volumes and call lengths	Meter reading services often generate customer calls associated with meter reading issues, billing issues, move-in/move-outs, and trouble calls. With on-request, daily, or monthly reads from AMI, these calls can be reduced, thereby decreasing customer call volume, call duration time, and call center agent handling calls on meter-related complaints and issues. Other calls that may be reduced include calls associated with payment options and credit & collections. Decreasing call volumes and call lengths can decrease call center staffing. During the initial years of deployment there is an expectation that calls associated with new metering and disconnects will increase.	Direct Expense Reductions	• Number of calls (by type) • Cost per call (by type) • Percent reduction (Reduction in Credit Calls = 5%, Reduction in Billing Calls = 5%, Reduction in Move Order Calls = 5%, Reduction in Electric & Gas Trouble Calls = 10%) • Increase in calls during the implementation period (Increase in Meter Reading calls - New Meters = 10%, Increase in Credit calls as start performing disconnects = 10%)	Year 2
Other	Increase in safety	Duke costs for workers' compensation associated with injuries incurred by employees during meter reading can be reduced upon adoption of an AMI system, as meter readers would no longer be exposed to high crime areas, dogs, fences, adverse weather, etc. Costs associated with vehicular accidents occurring during travel between meter reading locations in the field and premises would also be eliminated with AMI systems. This will also be seen as a benefit from the customer perspective as AMI deployment will greatly reduce the need for premise access. (Due to fewer personnel (meter readers, etc.) in the field, a corresponding decrease in the cost to provide insurance and to handle accident claims. We assume that the costs to settle accident claims associated with meter reading will be eliminated with SmartGrid.)	Direct Expense Reductions	Workman's compensation: • Present cost of insurance ($1,530,000) - $500 per person • Percent reduction in insurance (.5.88%) Accident claims: • Present cost ($15,000)	Year 2
Other	Billing savings - Shortened billing cycle	With AMI equipment, meter reads to provide billing should almost always be available on the read day, thereby allowing bills to go out on the next day. Bills that have typically gone out on Day 2 of the billing cycle (10% of the bills) or on Day 3 of the billing cycle as an estimated bill (about 5000 bills a month) will now be able to be issued on Day 1. Due dates of bills are directly tied to the mail date (Mail date + 21 business days), so sending out bills on Day 1 will result in earlier due dates and thus receipt of funds earlier than if the bill went out on Day 2 or Day 3. This results in a	Increased Revenue	• Percentage of bills that don't go out on day 1 of the billing cycle (10%) • Electric Revenue • Discount rate • Days billing cycle reduced - 2	Year 2
Other	Billing savings - Reduction in estimated bills	With AMI equipment, meter reads to provide billing should almost always be available on the read day, thereby allowing bills to go out on the next day as an actual bill instead of an estimated bill. Associated with estimated bills is any increased costs in processing and answering questions concerning these bills. Reducing estimated bills reduces these costs which translates into a decreased workload for specific FTEs. The OPUC is also likely to see this as a win/win for customers, Commission, and Ohio utilities.	Direct Expense Reductions	• Present cost of billing exceptions in OH - $216,700 • Future cost of billing exceptions - $65,000	Year 2
Other	Reduction in costs associated with vehicle management (meter reading vehicles)	AMI system would eliminate associated costs related to vehicles used for meter reading. The benefit value includes all direct meter reading expenses, such vehicle O&M, vehicle insurance, and other vehicle costs, as well as any capital costs associated with the vehicles.	Direct Expense Reductions	• Number of meter reading vehicles - 106 (72 reduced) • Insurance premium / vehicle - $700 • Miles driven / year - 12,662 • Capital costs per mile - $1.06	Year 2

Customer / Societal Benefits

Benefit Category	Benefit Modeled	Description	Benefit Category	Inputs	Year Benefit Begins
Customer / Societal	Reduce the numbers of customers experiencing an outage	Distribution automation will not necessarily reduce the number of outage events (though it could through condition-based maintenance), but it will reduce the number of customers affected by an outage (SAIFI will be reduced). Using a study by Lawrence Berkeley National Laboratory (Source: LaCommare and Eto, "Cost of Power Interruptions to Electricity Consumers in the United States", Lawrence Berkeley National Laboratory, February 2006), EPRI revised estimated outage costs to account for time since the report as well as accounting for Midwest costs versus national costs. (June 2008 EPRI Report: "Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments")	Customer / Societal Benefits	• Customer interruptions avoided - 361,471 • Ohio CAIDI - 113.7 minutes • Report CAIDI - 197 minutes • Report residential customer outage costs - $6.87 • Report commercial customer outage costs - $1,367.12 • Report adjustments per minute: Residential - $.02, Commercial - $5.45	Year 4
Customer / Societal	Customer Feedback (Prius Effect)	Customer Feedback (Prius Effect) – This occurs when customers lower their usage when they are made aware of what their actual usage is. The EPRI report (June 2008 EPRI Report: "Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments") provides a potential range of annual household kWh reduction between 0% and 28%. It also identified an average of 6.4% reduction using an indirect method (organizing and analyzing consumption and cost data periodically, say monthly, and providing it to the consumer either in their bill or by some other means. This does not involve any additional equipment in the customer's home). The report also provides an average of 11.5% reduction for Direct method which is the installation of a screen or something in the customer's home. Since we are asking for LR recovery this would generate Avoided Cost benefits only. Avoided Cost Benefit (customer perspective) estimates are currently calculated as percentages of residential revenues (including generation), excluding fuel.	Customer / Societal Benefits	• Low case - 0% • Base case - 6.4% • High case - 28% • Residential electric revenues, excluding fuel and trackers	Year 4
Customer / Societal	PHEV (Plug-in Hybrid Electric Vehicle)	With PHEVs, there is considerable risk of electric power demand outstripping supply if people with PHEVs plug in their vehicle at 5 PM, upon arriving home from work. (Current estimates for the entire U.S. call for the possibility of 150 additional power plants - Avoiding a significant portion of these costs is the benefit associated with PHEVs)	Customer / Societal Benefits	• Low case - 2% market penetration (PHEV sales as percentage of all auto sales) • Base case - 10% market penetration (PHEV sales as percentage of all auto sales) • High case - 20% market penetration (PHEV sales as percentage of all auto sales) • Ohio PHEV sales - .93% of national estimates (Based on number of customers and total Duke Energy estimate of 5% of national PHEV sales) • Avoided demand cost - $72.38 ($ / kW Annualized) • Avoided On-Peak demand moved Off-Peak based on 50% 3 kW 220v and 50% 1.5 kW 110v batteries	Year 3
Customer / Societal	Macroeconomic Impacts (Multiplier Effects)	Estimates of the broader economic benefits from the installation of smart metering systems, distribution automation, and related IT investments. These are often referred to as the macroeconomic benefits or multiplier effects that arise from investments, both capital and O&M. (See testimony by Richard Stevie.) The Base Case is the average of the Low Case and High Case.	Customer / Societal Benefits	• Direct capital investment multipliers (Computer and electronic product manufacturing - 2.1250, Electrical equipment and appliance manufacturing - 1.9888, Information and data processing services - 2.0121 • Operational direct spending multipliers (Utilities - 1.3618, Computer and electronic product manufacturing - 2.1250, Electrical equipment and appliance manufacturing - 1.9888, Information and data processing services - 2.0121	Year 1

Results

Overall Ohio Financial Results

Incremental Project Financial Analysis

All values in millions	Year 1 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013	Year 6 2014	Year 7 2015	Year 8 2016	Year 9 2017	Year 10 2018
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Metering	$ 0.16	$ 2.52	$ 7.88	$ 14.82	$ 19.34	$ 21.31	$ 22.45	$ 23.19	$ 23.94	$ 24.72
DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Outage	$ -	$ -	$ 0.53	$ 0.92	$ 1.06	$ 1.14	$ 1.17	$ 1.20	$ 1.24	$ 1.27
Distribution	$ -	$ 0.59	$ 1.23	$ 8.55	$ 12.84	$ 16.42	$ 16.85	$ 17.29	$ 17.74	$ 18.22
Other	$ -	$ 0.19	$ 0.77	$ 1.38	$ 1.60	$ 1.75	$ 1.90	$ 1.96	$ 2.02	$ 2.08
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
IT: Back-Office Systems	$ 1.12	$ 2.82	$ 4.55	$ 5.13	$ 5.73	$ 6.00	$ 6.27	$ 6.54	$ 6.80	$ 7.07
Endpoint Equipment	$ 0.10	$ 0.40	$ 0.78	$ 1.05	$ 1.16	$ 1.21	$ 1.23	$ 1.25	$ 1.27	$ 1.29
Communication Equipment	$ 0.47	$ 1.44	$ 2.52	$ 3.00	$ 2.93	$ 3.06	$ 3.08	$ 3.11	$ 3.13	$ 3.15
Additional O&M	$ 1.98	$ 3.77	$ 4.64	$ 3.98	$ 4.09	$ 3.86	$ 4.09	$ 4.21	$ 4.35	$ 4.48
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
IT: Back-Office Systems	$ 1.85	$ 5.37	$ 7.74	$ 6.95	$ 4.83	$ 3.51	$ 2.28	$ 1.82	$ 1.57	$ 1.52
Endpoint Equipment	$ 0.99	$ 3.88	$ 7.58	$ 9.66	$ 9.90	$ 9.55	$ 8.95	$ 8.40	$ 7.97	$ 7.80
Communication Equipment	$ 0.63	$ 2.42	$ 4.70	$ 6.02	$ 6.23	$ 6.08	$ 5.79	$ 5.53	$ 5.33	$ 5.25
Installation / Deployment Labor	$ 0.48	$ 1.89	$ 3.72	$ 4.78	$ 4.91	$ 4.73	$ 4.45	$ 4.20	$ 4.00	$ 3.90
Distribution Automation	$ 0.35	$ 1.04	$ 1.70	$ 2.33	$ 2.94	$ 3.11	$ 2.88	$ 2.87	$ 2.49	$ 2.37
PMO	$ 0.13	$ 0.35	$ 0.53	$ 0.70	$ 0.81	$ 0.82	$ 0.77	$ 0.71	$ 0.67	$ 0.64
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Income tax	$ (2.79)	$ (7.38)	$ (10.57)	$ (9.78)	$ (8.10)	$ (6.82)	$ (5.58)	$ (4.83)	$ (4.25)	$ (3.92)
Payment of property tax (lagging)	$ -	$ -	$ 3.16	$ 8.56	$ 13.86	$ 15.62	$ 16.51	$ 15.87	$ 15.21	$ 14.55
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
IT: Back-Office Systems	$ 6.19	$ 9.43	$ 9.58	$ 3.25	$ 3.30	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49
Endpoint Equipment	$ 26.34	$ 52.71	$ 53.76	$ 16.89	$ 8.80	$ 1.57	$ 1.62	$ 1.65	$ 1.66	$ 3.40
Communication Equipment	$ 16.83	$ 32.26	$ 33.15	$ 11.50	$ 6.14	$ 2.27	$ 2.28	$ 2.28	$ 2.29	$ 2.35
nstallation / Deployment Labor Costs	$ 12.89	$ 25.80	$ 26.86	$ 8.92	$ 4.05	$ 1.01	$ 1.04	$ 1.07	$ 1.10	$ 1.19
Distribution Automation	$ 9.38	$ 9.67	$ 9.96	$ 10.27	$ 10.58	$ 0.02	$ 0.01	$ 0.01	$ 0.02	$ 0.01
PMO Costs	$ 3.40	$ 2.71	$ 2.79	$ 2.88	$ 1.48	$ 0.31	$ -	$ -	$ -	$ -
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Discount factor	$ 0.93	$ 0.86	$ 0.80	$ 0.75	$ 0.69	$ 0.64	$ 0.60	$ 0.56	$ 0.52	$ 0.48
PV	$ (70.38)	$ (112.39)	$ (104.98)	$ (29.82)	$ (13.30)	$ 7.04	$ 6.19	$ 6.11	$ 6.14	$ 5.39
Cumulative NPV	$ (70.38)	$ (182.77)	$ (287.75)	$ (317.57)	$ (330.87)	$ (323.83)	$ (317.64)	$ (311.53)	$ (305.38)	$ (299.99)
Real NPV	$ (294.35)									

Duke Energy

SmartGrid Cost / Benefit Model – DE-Ohio

Incremental Project Financial Analysis (continued)

All values in millions	Year 11 2019	Year 12 2020	Year 13 2021	Year 14 2022	Year 15 2023	Year 16 2024	Year 17 2025	Year 18 2026	Year 19 2027	Year 20 2028
Benefit: Utility of the Future	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
Metering	$ 25.51	$ 26.35	$ 27.20	$ 28.09	$ 29.00	$ 29.94	$ 30.91	$ 31.81	$ 32.93	$ 33.99
DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Outage	$ 1.31	$ 1.34	$ 1.38	$ 1.42	$ 1.45	$ 1.49	$ 1.54	$ 1.58	$ 1.62	$ 1.67
Distribution	$ 18.72	$ 19.23	$ 19.76	$ 20.32	$ 20.90	$ 21.51	$ 22.13	$ 22.79	$ 23.48	$ 24.19
Other	$ 2.16	$ 2.21	$ 2.28	$ 2.35	$ 2.43	$ 2.50	$ 2.58	$ 2.66	$ 2.74	$ 2.83
O&M Expenses	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
IT: Back-Office Systems	$ 7.34	$ 7.61	$ 7.88	$ 8.15	$ 8.42	$ 8.69	$ 8.96	$ 9.23	$ 9.50	$ 9.77
Endpoint Equipment	$ 1.31	$ 1.33	$ 1.35	$ 1.38	$ 1.40	$ 1.42	$ 1.44	$ 1.47	$ 1.49	$ 1.52
Communication Equipment	$ 3.17	$ 3.19	$ 3.22	$ 3.24	$ 3.26	$ 3.29	$ 3.31	$ 3.33	$ 3.35	$ 3.38
Additional O&M	$ 4.62	$ 4.77	$ 4.91	$ 5.07	$ 5.23	$ 5.39	$ 5.56	$ 5.73	$ 5.91	$ 6.09
[illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
IT: Back-Office Systems	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49
Endpoint Equipment	$ 7.95	$ 8.25	$ 8.48	$ 8.59	$ 8.66	$ 8.84	$ 9.28	$ 9.82	$ 10.23	$ 10.54
Communication Equipment	$ 5.80	$ 7.32	$ 9.25	$ 10.42	$ 10.70	$ 10.70	$ 10.59	$ 10.50	$ 10.46	$ 10.52
Installation / Deployment Labor	$ 4.08	$ 4.64	$ 5.37	$ 5.84	$ 5.99	$ 6.13	$ 6.42	$ 6.80	$ 7.04	$ 7.13
Distribution Automation	$ 2.28	$ 2.24	$ 2.23	$ 2.23	$ 2.23	$ 2.23	$ 2.23	$ 2.24	$ 2.24	$ 2.24
PMO	$ 0.62	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61	$ 0.61
[illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
Income tax	$ (4.05)	$ (4.72)	$ (5.57)	$ (6.02)	$ (6.03)	$ (5.96)	$ (5.98)	$ (6.07)	$ (6.08)	$ (6.03)
Payment of property tax (lagging)	$ 13.89	$ 13.34	$ 13.27	$ 13.53	$ 13.59	$ 13.11	$ 12.46	$ 11.88	$ 11.44	$ 11.05
[illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
[illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
IT: Back-Office Systems	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49	$ 1.49
Endpoint Equipment	$ 5.31	$ 5.53	$ 3.05	$ 2.53	$ 2.01	$ 5.77	$ 8.86	$ 9.01	$ 6.11	$ 6.81
Communication Equipment	$ 15.88	$ 28.22	$ 28.92	$ 11.70	$ 7.45	$ 4.43	$ 4.42	$ 4.41	$ 4.46	$ 4.51
Installation / Deployment Labor Costs	$ 6.00	$ 10.67	$ 11.19	$ 4.95	$ 3.48	$ 5.02	$ 7.56	$ 7.92	$ 4.33	$ 3.34
Distribution Automation	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02
PMO Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
[illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
Discount factor	$ 0.45	$ 0.42	$ 0.39	$ 0.36	$ 0.33	$ 0.31	$ 0.29	$ 0.27	$ 0.25	$ 0.23
PV	$ (3.27)	$ (9.27)	$ (7.37)	$ 2.21	$ 4.49	$ 3.96	$ 2.61	$ 2.82	$ 4.67	$ 4.79
Cumulative NPV	$ (303.26)	$ (312.53)	$ (319.90)	$ (317.70)	$ (313.20)	$ (309.24)	$ (306.63)	$ (303.81)	$ (299.14)	$ (294.35)
Real NPV										

SmartGrid Cost / Benefit Model – DE-Ohio

Incremental Project Financial Analysis (continued)

All values in millions		5-Year Total		20-Year Total		20-Year NPV
Benefit Utility of the future	$	74.41	$	840.66	$	353.01
Metering	$	44.73	$	456.17	$	192.87
DSM	$	-	$	-	$	-
Outage	$	2.51	$	23.33	$	9.99
Distribution	$	23.22	$	322.77	$	133.85
Other	$	3.95	$	38.39	$	16.31
[illegible]		[illegible]		[illegible]		[illegible]
IT: Back-Office Systems	$	19.34	$	137.56	$	60.68
Endpoint Equipment	$	3.49	$	23.85	$	10.73
Communication Equipment	$	10.35	$	58.62	$	27.37
Additional O&M	$	18.47	$	92.83	$	43.57
[illegible]		[illegible]		[illegible]		[illegible]
IT: Back-Office Systems	$	26.75	$	52.37	$	32.20
Endpoint Equipment	$	32.01	$	165.30	$	77.74
Communication Equipment	$	20.00	$	144.25	$	61.73
Installation / Deployment Labor	$	15.77	$	96.49	$	42.91
Distribution Automation	$	8.35	$	44.26	$	21.37
PMO	$	2.51	$	12.18	$	5.95
[illegible]		[illegible]		[illegible]		[illegible]
Income tax	$	(38.63)	$	(120.54)	$	(63.08)
Payment of property tax (lagging)	$	25.58	$	230.88	$	104.67
[illegible]		[illegible]		[illegible]		[illegible]
[illegible]		[illegible]		[illegible]		[illegible]
IT: Back-Office Systems	$	31.74	$	54.13	$	35.38
Endpoint Equipment	$	158.50	$	223.39	$	154.54
Communication Equipment	$	99.88	$	225.75	$	132.01
nstallation / Deployment Labor Costs	$	78.31	$	148.19	$	90.20
Distribution Automation	$	49.85	$	50.11	$	40.16
PMO Costs	$	13.26	$	13.57	$	11.11
[illegible]		[illegible]		[illegible]		[illegible]
Discount factor						
PV	$	(330.87)	$	(294.35)		
Cumulative NPV						
Real NPV						

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SmartGrid Cost / Benefit Model – DE-Ohio

Capital and O&M versus Savings (millions)

Category	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Capital Expenditures (millions)	$ 75.02	$ 132.37	$ 136.11	$ 53.70	$ 34.36	$ 6.66	$ 6.44	$ 6.52	$ 6.56	$ 8.45	$ 26.70
O&M Expenses (millions)	$ 3.66	$ 8.43	$ 12.48	$ 13.16	$ 13.91	$ 14.23	$ 14.67	$ 15.10	$ 15.55	$ 16.00	$ 16.45
Savings - Direct Expense Reductions (millions)	$ -	$ 1.63	$ 6.65	$ 13.31	$ 17.78	$ 19.75	$ 20.96	$ 21.67	$ 22.41	$ 23.16	$ 23.95
Savings - Increased Revenue (millions)	$ 0.16	$ 0.79	$ 1.78	$ 2.52	$ 2.76	$ 2.91	$ 2.98	$ 3.05	$ 3.11	$ 3.17	$ 3.23
Savings - Avoided Costs (millions)	$ -	$ 0.88	$ 1.98	$ 9.85	$ 14.30	$ 17.96	$ 18.43	$ 18.92	$ 19.42	$ 19.95	$ 20.50
Savings - Total (millions)	$ 0.16	$ 3.31	$ 10.42	$ 25.68	$ 34.84	$ 40.62	$ 42.37	$ 43.64	$ 44.94	$ 46.29	$ 47.68

Category	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	20-Year Total	20-Year NPV
	2020	2021	2022	2023	2024	2025	2026	2027	2028		
Capital Expenditures	$ 45.93	$ 44.67	$ 20.70	$ 14.45	$ 16.72	$ 22.34	$ 22.86	$ 16.42	$ 16.18	$ 715.13	$ 463.41
O&M Expenses	$ 16.91	$ 17.37	$ 17.83	$ 18.31	$ 18.78	$ 19.27	$ 19.75	$ 20.25	$ 20.75	$ 312.86	$ 142.35
Savings - Direct Expense Reductions (millions)	$ 24.76	$ 25.59	$ 26.45	$ 27.33	$ 28.25	$ 29.19	$ 30.16	$ 31.17	$ 32.20	$ 426.35	$ 178.99
Savings - Increased Revenue (millions)	$ 3.31	$ 3.39	$ 3.47	$ 3.55	$ 3.63	$ 3.71	$ 3.80	$ 3.88	$ 3.97	$ 59.18	$ 26.21
Savings - Avoided Costs (millions)	$ 21.06	$ 21.65	$ 22.27	$ 22.90	$ 23.57	$ 24.26	$ 24.98	$ 25.73	$ 26.51	$ 355.12	$ 147.81
Savings - Total (millions)	$ 49.13	$ 50.63	$ 52.18	$ 53.78	$ 55.44	$ 57.16	$ 58.94	$ 60.78	$ 62.68	$ 840.66	$ 353.01

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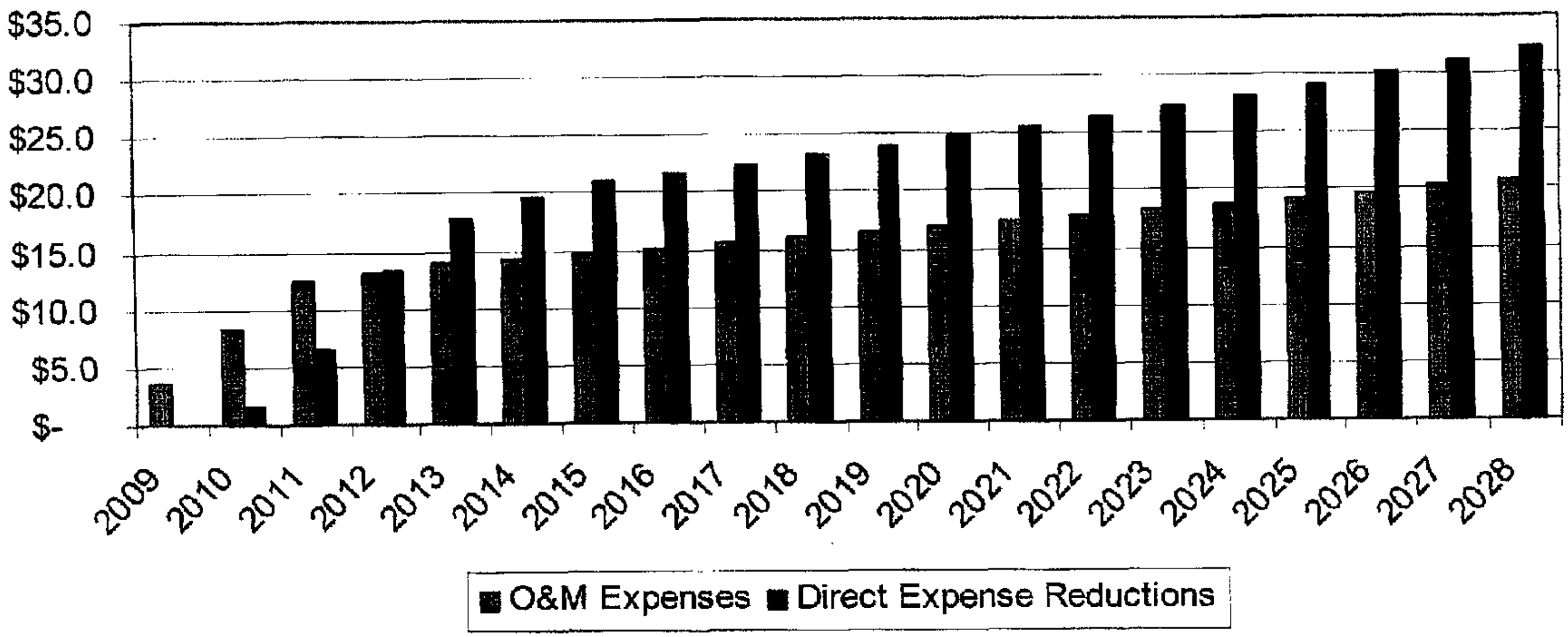
SmartGrid Cost / Benefit Model – DE-Ohio

O&M Expenses (Costs) versus Direct Expense Reductions (Benefits) (millions)

20-Year O&M Expenses:	$312.86 million
20-Year Direct Expense Reductions:	$426.35 million



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Duke Energy — SmartGrid Cost / Benefit Model – DE-Ohio

Capital Expenditures (millions)

	Year 1 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013	5-Year Total	20-Year Total	20-Year NPV
IT: Back-Office Systems	$ 6.19	$ 9.43	$ 9.58	$ 3.25	$ 3.30	$ 31.74	$ 54.13	$ 35.38
Endpoint Equipment	$ 26.34	$ 52.71	$ 53.76	$ 16.89	$ 8.80	$ 158.50	$ 223.39	$ 154.54
Communication Equipment	$ 16.83	$ 32.26	$ 33.15	$ 11.50	$ 6.14	$ 99.88	$ 225.75	$ 132.01
Installation / Deployment Labor Costs	$ 12.89	$ 25.60	$ 26.86	$ 8.92	$ 4.05	$ 78.31	$ 148.19	$ 90.20
Distribution Automation	$ 9.38	$ 9.67	$ 9.96	$ 10.27	$ 10.58	$ 49.85	$ 50.11	$ 40.16
PMO Costs	$ 3.40	$ 2.71	$ 2.79	$ 2.88	$ 1.48	$ 13.26	$ 13.57	$ 11.11
Total	$ 75.02	$ 132.37	$ 136.11	$ 53.70	$ 34.36	$ 431.56	$ 715.13	$ 463.41

Operational Benefits (millions)

Benefit Category	Benefit	Savings Category	5-Year Total	20-Year Total	20-Year NPV
Metering	Regular meter reads	Direct Expense Reductions	$ 10.51	$ 151.99	$ 62.58
Metering	Off-cycle / off-season reads	Direct Expense Reductions	$ 19.54	$ 184.77	$ 78.31
Metering	Remote diagnostics (for individual customer events)	Direct Expense Reductions	$ 1.82	$ 17.38	$ 7.36
Metering	Power theft - Recovery	Increased Revenue	$ 5.47	$ 45.03	$ 19.66
Metering	Power theft - Theft recovery budget	Direct Expense Reductions	$ -	$ -	$ -
Metering	Meter operations - Avoided capital costs	Avoided Costs	$ 4.88	$ 43.11	$ 18.54
Metering	Meter operations - Decrease annual expenses	Direct Expense Reductions	$ 1.05	$ 9.35	$ 4.01
Metering	Meter accuracy improvement	Increased Revenue	$ 0.42	$ 3.43	$ 1.50
Metering	Meter Salvage Value	Increased Revenue	$ 1.05	$ 1.11	$ 0.90
Outage	Outage Detection	Direct Expense Reductions	$ 0.17	$ 1.59	$ 0.68
Outage	Outage Verification	Direct Expense Reductions	$ 1.44	$ 13.67	$ 5.83
Outage	Outage - Incremental Revenue	Increased Revenue	$ 0.90	$ 8.06	$ 3.48
Distribution	System Voltage Control	Avoided Costs	$ 16.39	$ 255.31	$ 104.70
Distribution	Power Shortage Voltage Reduction	Avoided Costs	$ 0.53	$ 7.41	$ 3.09
Distribution	Continuous Voltage Monitoring	Direct Expense Reductions	$ 0.56	$ 5.04	$ 2.17
Distribution	VAR Management	Avoided Costs	$ 2.11	$ 17.90	$ 7.98
Distribution	Asset Management	Avoided Costs	$ 1.40	$ 11.90	$ 5.31
Distribution	System Fine-tuning	Avoided Costs	$ 1.71	$ 19.48	$ 8.20
Distribution	Capacitor Inspections	Direct Expense Reductions	$ 0.34	$ 3.77	$ 1.59
Distribution	Circuit Breaker Inspections	Direct Expense Reductions	$ 0.18	$ 1.95	$ 0.82
Other	Call center efficiency	Direct Expense Reductions	$ 0.03	$ 2.93	$ 1.12
Other	Increase in safety	Direct Expense Reductions	$ 0.31	$ 2.98	$ 1.26
Other	Pre-payment options - Fewer staff	Direct Expense Reductions	$ -	$ -	$ -
Other	Pre-payment options - Fewer losses from uncollectible accounts	Increased Revenue	$ -	$ -	$ -
Other	Billing savings - Shortened billing cycle	Increased Revenue	$ 0.18	$ 1.55	$ 0.67
Other	Billing savings - Reduction in estimated bills	Direct Expense Reductions	$ 0.46	$ 4.38	$ 1.85
Other	Vehicle Management	Direct Expense Reductions	$ 2.97	$ 26.55	$ 11.40
	Total		$ 74.41	$ 840.66	$ 353.01

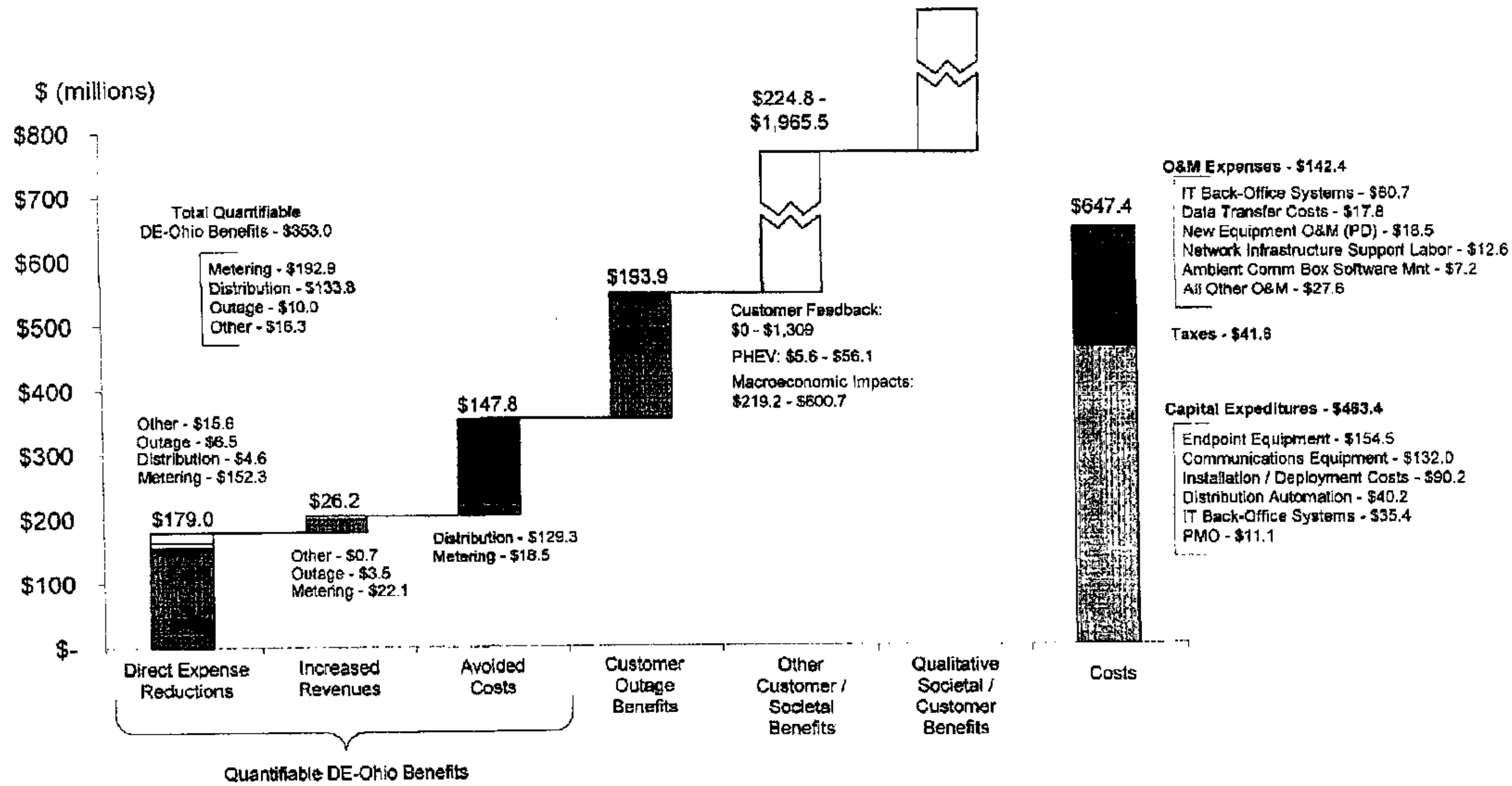
Operations & Maintenance (O&M) (millions)

	Year 1 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013	5-Year Total	20-Year Total	20-Year NPV
Endpoint Ongoing Costs	$ 0.06	$ 0.25	$ 0.51	$ 0.68	$ 0.74	$ 2.26	$ 14.44	$ 6.61
Endpoint Power Cost	$ 0.03	$ 0.14	$ 0.27	$ 0.37	$ 0.42	$ 1.23	$ 9.41	$ 4.13
Comm Ongoing Costs	$ 0.45	$ 1.36	$ 2.36	$ 2.78	$ 2.69	$ 9.64	$ 53.39	$ 25.05
Comm Power Costs	$ 0.02	$ 0.08	$ 0.16	$ 0.21	$ 0.24	$ 0.71	$ 5.23	$ 2.31
Maintenance for Management Tools	$ 0.03	$ 0.03	$ 0.04	$ 0.05	$ 0.06	$ 0.21	$ 1.39	$ 0.62
Maintenance for Central Network	$ 0.03	$ 0.04	$ 0.05	$ 0.06	$ 0.07	$ 0.24	$ 1.49	$ 0.68
Network Infrastructure Support Labor	$ -	$ 0.19	$ 0.60	$ 1.07	$ 1.26	$ 3.12	$ 29.58	$ 12.63
IT Back-Office Systems O&M	$ 1.12	$ 2.82	$ 4.55	$ 5.13	$ 5.73	$ 19.34	$ 137.56	$ 60.68
Tollgrade System Administrator	$ 0.15	$ 0.16	$ 0.16	$ 0.17	$ 0.17	$ 0.81	$ 4.10	$ 1.93
New Equipment O&M (Power Delivery)	$ 0.26	$ 0.70	$ 1.17	$ 1.43	$ 1.64	$ 5.21	$ 37.33	$ 16.48
Meter Disposal FTEs	$ 0.33	$ 0.35	$ 0.14	$ 0.10	$ 0.11	$ 1.02	$ 1.02	$ 0.86
Meter Testing FTEs	$ 0.20	$ 0.22	$ 0.12	$ 0.03	$ 0.01	$ 0.58	$ 0.58	$ 0.50
Customer Service (Call Center) O&M	$ 0.90	$ 1.84	$ 1.94	$ 0.59	$ 0.26	$ 5.53	$ 5.63	$ 4.61
Power Theft FTEs	$ 0.08	$ 0.24	$ 0.42	$ 0.48	$ 0.52	$ 1.75	$ 11.81	$ 5.27
Total	$ 3.66	$ 8.43	$ 12.48	$ 13.16	$ 13.91	$ 51.65	$ 312.86	$ 142.35

SmartGrid Cost / Benefit Model – DE-Ohio

Summary Ohio Results – Graphic (All values are 20-Year NPV in $ millions)

NPV (excluding Customer Outage / Reliability Benefits) = ($294.35 million)
NPV (including Customer Outage / Reliability Benefits) = ($100.50 million)



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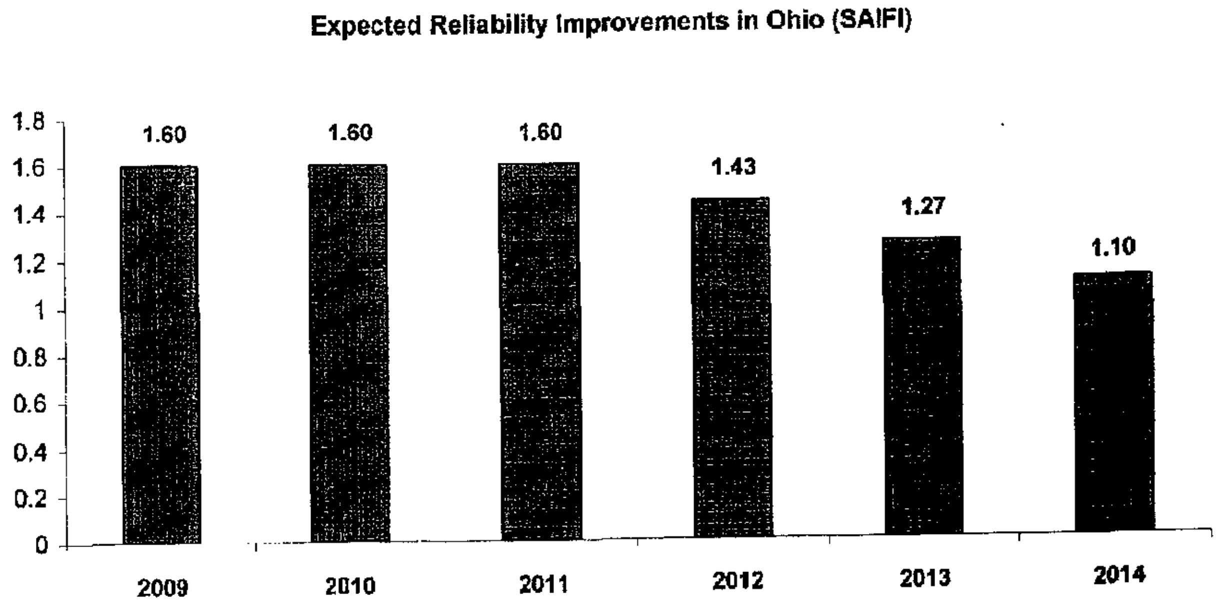
SmartGrid Cost / Benefit Model – DE-Ohio

Reliability Improvements



- Project 361,471 avoided customer interruptions (outages) – SAIFI reduced from 1.60 to 1.10
  - New distribution automation relays – SAIFI reduced .20 – 144,588 customer interruptions)
  - Sectionalization – SAIFI reduced .25 – 180,735 customer interruptions
  - Self-Healing Technology – SAIFI reduced .05 – 36,147 customer interruptions)

Communication Equipment Sensitivity Analysis

There is a degree of uncertainty in modeling the communications equipment for SmartGrid, due to both cost/pricing variability and the attention this equipment is receiving from federal and state authorities in terms of depreciation lives. Due to these considerations, sensitivity analysis was performed on various characteristics of communications equipment to understand the impact on the overall SmartGrid cost/benefit analysis.

SmartGrid Cost/Benefit Model (millions)

Version	NPV	5-Year CapEx	20-Year CapEx
Base Case with Annual Inflation Applied to Communications Equipment	$ (320.87)	$ 438.79	$ 761.66
[redacted]			
Base Case with 10-15% (12.5%) Reduction on Communication Equipment Costs Starting in Year 11 (Sensitivity 1)	$ (289.28)	$ 431.56	$ 700.83
Base Case with 25% Reduction on Communications Equipment Costs Starting in Year 11 (Sensitivity 2)	$ (284.22)	$ 431.56	$ 686.53
Base Case with 10-Year Tax Depreciation Life on Communications Equipment (Sensitivity 3)	$ (275.97)	$ 431.56	$ 715.13
Base Case with 10-Year Tax Depreciation Life on Communications Equipment and 25% Reduction on Communications Equipment Costs Starting in Year 11 (Sensitivity 4)	$ (267.05)	$ 431.56	$ 686.53

[1]Base Case - Deployment plan of approximately 97,000 meters in 2008 and 125,000 meters in 2009; no inflation on communications equipment costs

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SmartGrid Cost / Benefit Model – DE-Ohio

Customer / Societal Benefits - Summary

Customer / Societal Benefits[1] (millions)

Benefit	Low Case	Base Case	High Case
Customer Outage / Reliability Benefits[2]	$ 155.08	$ 193.85	$ 232.63
Customer Feedback (Prius Effect)[3]	$ -	$ 392.61	$ 1,308.70
PHEV[4]	$ 5.61	$ 28.05	$ 56.10
Macroeconomic Impacts (Multiplier Effects)[5]	$ 219.16	$ 409.95	$ 600.73
Total Reliability (First item)	$ 155.08	$ 193.85	$ 232.63
Total Societal/Customer Benefits	$ 379.85	$ 1,024.46	$ 2,198.16

[1]Societal and customer benefit calculations are not as detailed as the cost/benefit analysis; they are primarily a high-level range of estimates of the benefit expectations. They use industry estimates and studies which are then applied to DE-Ohio specific data. No detailed DE-Ohio specific studies were conducted.

[2]Based upon June 2008 EPRI Report: "Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments" and LaCommare and Eto, "Cost of Power Interruptions to Electricity Consumers in the United States", Lawrence Berkeley National Laboratory, February 2006. Low Case is improvement in SAIFI from 1.6 to 1.2, Base Case is improvement in SAIFI from 1.6 to 1.1, and High Case is improvement in SAIFI from 1.6 to 1.0.

[3]Customer Feedback (Prius Effect) – This occurs when customers lower their usage when they are made aware of what their actual usage is. The EPRI report (June 2008 EPRI Report: "Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments") provides a potential range of annual household kWh reduction between 0% and 28%. It also identified an average of 8.4% reduction using an indirect method (organizing and analyzing consumption and cost data periodically, say monthly, and providing it to the consumer either in their bill or by some other means. This does not involve any additional equipment in the customer's home). The report also provides an average of 11.5% reduction for Direct method which is the installation of a screen or something in the customer's home. Since we are asking for LR recovery this would generate Avoided Cost benefits only. There is also a small kW (.1 to .2) benefit as well, as identified by the EPRI report. Low Case is 0%, Base Case is 8.4%, High Case is 28%. Avoided Cost Benefit (customer perspective) estimates are currently calculated as percentages of residential revenues (including gene

[4]Assumptions: SmartGrid in place; Off-Peak charging; Ohio sales is 0.93% of national sales (based on DE estimate of 5% scaled down by # of residential OH customers); Numbers are very high level, based on industry estimates which vary widely; Avoided On-Peak demand moved Off-Peak based on 50% 3 kW 220v and 50% 1.5 kW 110v batteries; Avoided Demand Cost based on data from DSMore software avoided cost analysis ($72.36) and escalated at 4% per year. Low Case = 2% penetration, Base Case = 10% penetration, High Case = 20% penetration.

[5]Estimates of the broader economic benefits from the installation of smart metering systems, distribution automation, and related IT investments. These are often referred to as the macroeconomic benefits or multiplier effects that arise from investments, both capital and O&M. These were calculated by Richard Stevie. The Base Case is the average of the Low Case and High Case provided by Richard Stevie.

EXHIBIT E

NCSEA
Docket No. E-100, Sub 141
NCSEA Data Request No. 1
2014 Smart Grid Technology Plans
Item No. 1-2

DUKE ENERGY CAROLINAS

Request:

Please provide data detailing DEC's installation of AMI metering equipment, including number of meters installed, type(s) of meters installed, date(s) of installation (broken down by number and type installed), and remaining useful life of the equipment (broken down by number and type installed).

Response:

Please see p. 33 of the 2014 DEC Smart Grid Technology Plan, page 33.

As an additional update, as of 10/30/2014, DEC has installed 362,556 AMI meters as part of its on-going project scheduled to conclude by the end of 2014. Approximately 244,200 are for residential, 1,400 for residential time-of-use, 98,400 for commercial, and 18,600 for commercial time-of-use customers. These are further broken down into residential, residential time-of-use, commercial, and commercial time-of-use by state and meter type in the table below.

DEC's AMI meters have a planned lifecycle of approximately 15-20 years, and therefore remaining useful life will vary by installation date.

DEC AMI Meters

YEAR As of 10/30/2014
CUSTOMER TYPE /
METER TYPE 2012 2013 2014 Total
NORTH CAROLINA TOTALS 14 92,839 182,275 275,128
COMMERCIAL 12 66,727 9,940 76,679
C12M3 2 743 92 837
C12NM 19 154 173
C16M3 5 23,161 1,848 25,014
C1M 1 1
C2M 3,703 900 4,603
C2M3 1 8,083 868 8,952
C3M 3 3,330 584 3,917
C5M 1 13,344 2,262 15,607
C9M 14,344 3,231 17,575

Response Continued:

COMMERCIAL_TOU 2 11,786 2,717 14,505
C12M3 41 16 57
C12NM 5 4 9
C16M3 1,299 327 1,626
C2M 58 9 67
C2M3 1,562 389 1,951
C3M 325 61 386
C5M 1 4,053 766 4,820
C9M 1 4,443 1,145 5,589
RESIDENTIAL 13,393 169,285 182,678
C12M3 300 160 460
C12NM 35 17,075 17,110
C16M3 1,263 7,883 9,146
C2M 11,089 143,757 154,846
C2M3 369 287 656
C3M 39 28 67
C5M 167 51 218
C9M 131 44 175
RESIDENTIAL_TOU 933 333 1,266
C12M3 1 1
C16M3 2 1 3
C2M 84 44 128
C2M3 695 251 946
C3M 148 34 182
C5M 4 2 6
SOUTH CAROLINA TOTALS 9 30,451 56,968 87,428
COMMERCIAL 5 20,409 1,289 21,703
C12M3 271 19 290
C12NM 1 89 90
C16M3 2 6,733 331 7,066
C2M 1,845 253 2,098
C2M3 3,051 248 3,299
C3M 727 19 746
C5M 1 4,028 110 4,139
C9M 2 3,753 220 3,975
COMMERCIAL_TOU 3 3,923 196 4,122
C12M3 12 2 14
C12NM 2 2
C16M3 544 36 580

Response Continued:

C2M 39 16 55
C2M3 532 24 556
C3M 99 3 102
C5M 2 1,220 30 1,252
C9M 1 1,475 85 1,561
RESIDENTIAL 1 5,998 55,481 61,480
C12M3 70 86 156
C12NM 2 2,684 2,686
C16M3 1 228 2,884 3,113
C2M 5,520 49,577 55,097
C2M3 60 232 292
C3M 13 2 15
C5M 60 9 69
C9M 45 7 52
RESIDENTIAL_TOU 121 2 123
C2M 9 1 10
C2M3 87 1 88
C3M 23 23
C5M 2 2
GRAND TOTAL 23 123,290 239,243 362,556

EXHIBIT F

NCSEA
Docket No. E-100, Sub 141
NCSEA Data Request No. 2
2014 Smart Grid Technology Plans
Item No. 2-1

DUKE ENERGY PROGRESS

Request:

Please provide data detailing DEP's installation of AMI metering equipment broken down by number of North Carolina and South Carolina installations to date. Please refer to NCSEA DR No. 1, Item No. 1-2.

Response:

The breakdown of AMI meters currently installed by DEP is 54,706 AMI meters installed in North Carolina and 7,850 AMI meters installed in South Carolina.

EXHIBIT G

DUKE ENERGY CAROLINAS

Request:

Please identify any time-of-use (TOU) pricing rates DEC currently offers to its customers broken down by customer/account type/class. Please provide the number of customer accounts currently enrolled in each rate. Please include any TOU pricing rates that DEC plans to offer to its customer in the next five years.

Response:

DEC objects to this question on the grounds that it seeks information that was not used or relied upon in developing the DEC 2014 Smart Grid Technology Plan and therefore seeks information that is not likely to lead to the discovery of admissible evidence. Notwithstanding the objection, and in the spirit of cooperation, please see the information provided below.

Customer accounts enrolled in time-of-use (TOU) rates (North Carolina only):

Rate Schedule

Customer Class

Number of Accounts
RST Residential Service, Time of Use (Pilot) Residential 217
RET Residential Service, All Electric, Time of Use (Pilot) Residential 212
RT Residential Service, Time of Use Residential 1,911
SGST Small General Service, Time of Use (Pilot) Commercial 104
OPT-E Optional Power Service, Time of Use, Energy only, Pilot Commercial 1
OPT-H Optional Power Service, Time of Use, High Load Factor Commercial 29
OPT-G Optional Power Service, Time of Use, General Service Commercial 15,759
PG Parallel Generation Commercial 4
OPT-I Optional Power Service, Time of Use, Industrial Service Industrial 1,131

PG Parallel Generation Industrial 3

Effective January 1, 2015, all customers currently receiving service under Rate Schedules OPT-I, OPT-G, and OPT-H will be transferred to the new OPT-V rate schedule, which received approval September 19, 2014 in Docket No. E-7 Sub 1026. DEC has no other proposed time-of-use rate offerings planned at this time.

EXHIBIT H

DUKE ENERGY PROGRESS

Request:

Please identify any time-of-use (TOU) pricing rates DEP currently offers to its customers broken down by customer/account type/class. Please provide the number of customer accounts currently enrolled in each rate. Please include any TOU pricing rates that DEP plans to offer to its customer in the next five years.

Response:

DEP objects to this question on the grounds that it seeks information that was not used or relied upon in developing the DEP 2014 Smart Grid Technology Plan. Notwithstanding the objection, in the spirit of cooperation, please see the information provided below.

Current North Carolina Time-of-Use Tariffs Customer Count September 2014
Residential Customer Class
Residential Service Time of Use Schedule R-TOUD-28* 24,162
Residential Service Time of Use Schedule R-TOU-28 1,225
Small General Service Rate Class (Commercial, Industrial, & Governmental)
Contract Demands below 30 kW
Small General Service (All-Energy) Time of Use Schedule SGS-TOUE-28 203
Medium General Service Rate Class (Commercial, Industrial, & Governmental)
Contract Demands from 30 to 999 kW
Small General Service Time of Use Schedule SGS-TOU-28 25,956
Church Service (Time-of-Use) Schedule CH-TOUE-28 224
General Service (Thermal Energy Storage) Schedule GS-TES-28 (available for contract demands of 4,000 kW or less) 4
Agricultural Post-Harvest (Experimental Thermal Energy Storage) Schedule GS-TES-28 3
Large General Service Rate Class (Commercial, Industrial, & Governmental)
Contract Demands of 1,000 kW or greater
Large General Service Time of Use Schedule SGS-TOU-28 108
* Not available to new applicants.

At this time, DEP has no plans to offer new time-of-use rates in the next 5 years.

EXHIBIT I

Dominion North Carolina Power
2014 IRP- REPS Compliance – Docket No. E-100, Sub 141
North Carolina Sustainable Energy Association
Data Request No. 2

The following response to Question No. 16 of the North Carolina Sustainable Energy Association Data Request No. 2, dated October 27, 2014, has been prepared under my supervision.

Heather M. Jennings
Manager, Advanced Metering Solutions and Meter Data Management

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Smart Grid Technology Plans

Question No. 16:

Does DNCP or any of its affiliates participate and/or plan to participate in the U.S. DOE Green Button initiative? Please provide details, if applicable, of the types of information DNCP or its affiliates provides to customers?

Response:

As mentioned on page on page 6 of the Company's Smart Grid Technology Plan, DNCP is a participating Green Button partner. Customers on time-of-use rates can use Green Button to view interval usage data in a consumer- and computer-friendly format.

EXHIBIT J

Dominion North Carolina Power
2014 IRP- REPS Compliance – Docket No. E-100, Sub 141
North Carolina Sustainable Energy Association
Data Request No. 2

The following response to Question No. 17 of the North Carolina Sustainable Energy Association Data Request No. 2, dated October 27, 2014 has been prepared under my supervision.

Paul B. Haynes
Director - Regulation

Question No. 17:

Please identify any time-of-use (TOU) pricing rates DNCP currently offers to its customers broken down by customer/account type/class. Please provide the number of customer accounts currently enrolled in each rate. Please include any TOU pricing rates that DNCP plans to offer to its customers in the next five years.

Response:

Below is a summary showing the TOU pricing schedules DNCP currently offers and the number of customers currently enrolled on each schedule. Confidential information is highlighted in yellow and is provided pursuant to the protections set forth in the executed Confidentiality Agreement between DNCP and NCSEA.

The Company has not decided on any future rate offerings at this time. A complete list of the Company's tariff offerings is available on-line at:

https://www.dom.com/residential/dominion-north-carolina-power/customer-service/rates-and-regulation/residential-rate-schedules and:

https://www.dom.com/business/dominion-north-carolina-power/rates/business-rate-schedules

Confidential information highlighted in yellow

	AS OF SEPT 2014	
	CUSTOMERS	TYPE
RESIDENTIAL		
1P	259	TOU
1T	53	TOU
TOTAL	312	

EXHIBIT K

DUKE ENERGY CAROLINAS

Request:

Please provide any cost-benefit analysis/analyses associated with DEC for making smart grid investments. Please include any cost-benefit analysis/analyses associated with DEC for making smart grid investments during the past three years.

Response:

Costs and benefits of smart grid investments are outlined within the DEC 2014 Smart Grid Technology Plan, Section 4.

EXHIBIT L

DUKE ENERGY PROGRESS

Request:

Please provide any cost-benefit analysis/analyses associated with DEP for making smart grid investments. Please include any cost-benefit analysis/analyses associated with DEP for making smart grid investments during the past three years.

Response:

Costs and benefits of smart grid investments are outlined within the DEP 2014 Smart Grid Technology Plan, Section 4.

EXHIBITS **M**, **N**, AND **O** HAVE BEEN REDACTED FROM THIS PUBLIC VERSION