FILE

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PUCO

VIA OVERNIGHT MAIL

October 6, 2008

Ms. Renee Jenkins
Public Utilities Commission of Ohio
Docketing Division
13th Floor
180 East Broad Street
Columbus, OH 43215-3716

Re: In re Duke Energy Ohio's Application for an Electric Security Plan
Case No. 08-920-EL-SSO

Dear Ms. Jenkins:

Enclosed with this cover are four documents which Duke Energy Ohio is submitting for filing in the above captioned case. The documents include the following:

1. Attachment TES-1, an exhibit which should be included with the Direct Testimony of Theodore E. Schultz.
2. Attachment 4, to Direct Testimony of Richard G. Stevie, PhD. Mr. Stevie's testimony included this attachment, however, this is a corrected version.
3. Direct testimony of Christopher D. Kiergan, unredacted and now to be publicly filed. We hereby withdraw the redacted version and the related request for confidential treatment.
4. Direct testimony of Richard G. Stevie, unredacted and now to be publicly filed. We hereby withdraw the redacted version and the related request for confidential treatment. Please note that this testimony has been supplemented on September 16, 2008.

Please include these documents in the above styled case.

Sincerely,

Elizabeth H. Watts/ams

Elizabeth H. Watts

EHW/bsc

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing letter filing with attachments of Duke Energy Ohio was served on the following parties this 6th day of October 2008 by regular U. S. Mail, overnight delivery or electronic delivery.

Elizabeth H. Watts / ams

Elizabeth H. Watts

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RESIDENTIAL PROGRAMS

- Home Energy House Call
- AC Check Pilot
- Smart Saver/Summer Saver
- Power Manager
- Energy Star Products
- Energy Efficiency Website
- Ohio Energy Project
- Appliance Turn-In
- Personalized Energy Report
- Pre-Paid Billing Services

COMMERCIAL PROGRAMS

- Commercial & Industrial (C&I) Prescriptive Incentive Program
    - School Incentive Program
- Photovoltaic Schools Demonstration/Education Program

RESEARCH

- House Call Plus Research Program

RESIDENTIAL PROGRAMS:

1. Home Energy House Call

The Home Energy House Call program (HEHC) is an in-home energy analysis that helps consumers determine the most cost-effective steps they can take in their home to save energy. The analysis looks at potential efficiency improvements from insulation to equipment replacement. Data taken from the analysis is run through a computer model to make recommendations and disaggregate the energy bill into usage categories. The results are mailed to the participant. This program will be jointly implemented with the Duke Energy Indiana and Duke Energy Kentucky territory to reduce administrative costs and leverage promotion.

2. AC Check – Test Program

Air conditioners are a large user of electricity during Duke Energy Ohio's summer peak season and, as such, their use and operation can negatively impact the Duke Energy Ohio system if they are running improperly. To address this, Duke Energy Ohio is testing during the 2006 summer season, a central air conditioning tune up and recharge program to increase efficiency of units. Using the Check Me! program developed in California, Duke Energy Ohio will work with contractors to test the savings available from these maintenance improvements.

3. Smart $aver®/Summer Saver

Electric Measures : Heat Pumps and Air Conditioners

The electric portion of the Smart $aver®/Summer Saver program provides market incentives and market support to consumers, heating contractors and new home builders to promote the use of high efficiency heat pumps with electronically commutated motors (ECM) and high efficiency Energy Star central air conditioners. Monetary incentives and technical support to trade ally sales personnel stimulate demand for the high efficient equipment options. This program will be jointly implemented with the Duke Energy Indiana territory to reduce administrative costs and leverage promotion.

Gas Measures: Gas Furnaces and Gas Furnaces with ECM Motors

The gas portion of the Smart $aver®/Summer Saver program provides market incentives and market support to consumers, heating contractors and new home builders to promote the use of high efficiency high efficiency gas furnaces with and without ECM motors. Monetary incentives and technical support to trade ally sales personnel stimulate demand for the high efficient equipment options. This program will be jointly implemented with the Duke Energy Indiana territory to reduce administrative costs and leverage promotion.

4. Power Manager

The purpose of the Power Manager program is to reduce demand by controlling residential air conditioning usage during peak demand conditions in the summer months. The program is offered to residential consumers with central air conditioning. Duke Energy Ohio would attach a load control device to the consumer's compressor to enable Duke Energy Ohio to cycle the consumer's air conditioner off and on when the load on Duke Energy Ohio's system reaches peak levels. Consumers receive financial incentives for participating in this program based upon the cycling option selected. This program will be jointly implemented with the Duke Energy Indiana and Duke Energy Kentucky territories to reduce administrative costs and leverage promotion.

5. Energy Star Products

The Energy Star Products program provides market incentives and market support through retailers to build market share and usage of Energy Star products. Special incentives to buyers and in-store support stimulate demand for the products and make it easier for store participation. The program targets Residential consumers' purchase of specified technologies through retail stores and special sales events. The first year of the program focuses on compact fluorescent lamps (bulbs) and torchiere lamps. This program will be jointly implemented with the Duke Energy Kentucky territory to reduce administrative costs and leverage promotion.

6. Energy Efficiency Website

Energy Zone™ is Duke Energy Ohio's enhanced energy efficiency web site. It provides Duke Energy Ohio consumers the most advanced programs, tools, and measures available to manage their energy and achieve load impacts. The website features a multi-tiered design providing the consumer the opportunity to receive quick customized energy tips and, if they choose, the ability to complete an online audit and receive ten (10) self-install energy efficiency measures. The marketing of the Energy Efficiency Website is an initiative meant to diversify and increase the reach of Duke Energy Ohio's DSM programs.

7. Ohio Energy Project (NEED)

The Ohio Energy Project, a part of the National Energy Education Development (NEED), was previously part of the Ohio Collaborative activities before deregulation. The DECP Board would like to restart the support of this important education program for Ohio. NEED was launched in 1980 to promote student understanding of the scientific, economic, and environmental impacts of energy. The program is currently available in 36 states, the U.S. Virgin Islands, and Guam. The Ohio Energy Project (NEED) activities provide teachers and students in Ohio with the materials, skills and classes to promote energy education in the classroom. The program will also provide a limited number of energy efficiency "kits" that will allow students to directly install energy efficiency items in their homes as it relates to their curriculum. This allows learning and direct savings from the program. Duke Energy also supports NEED activities in its Kentucky and Indiana territories.

8. Appliance Turn-In

Older vintage room air conditioners (room AC) can be one of the least efficient electrical appliances in the home. Often these old units are used when they are not functioning properly and as a result use electricity very inefficiently. To encourage consumers to dispose of their old room air conditioners and purchase efficient Energy Star models, the DECP proposes a room AC turn-in program. Located at retailer locations during special promotions, participants would receive coupons towards more efficient units if they turn in an old unit. Units received will be recycled through a certified recycling agency.

9. Personalized Energy Report Pilot Program

The Personalized Energy Report (PER) will provide the Duke Energy Ohio consumer with a customized energy report aimed at helping them better manage their energy costs. With rising energy costs in all aspects of daily life, the consumer is searching for information they can use and ideas they can implement which will impact their monthly energy bill. The PER program also includes the "*Energy Efficiency Starter Kit*" which is nine easily installed measures which demonstrate how easy it is to move towards improved home energy efficiency.

10. Pre-Paid Billing Services

Providing consumers with the option of paying for their electrical use prior to consumption not only allows consumers to control their bills, but promotes energy savings. Implemented by several utilities around the country, "Pre-Paid Billing Services" or pre-paid meters provides participants with the metering to understand their energy usage and has resulted in 10% to 20% energy savings. The DECP is proposing to test this concept recruiting 100 consumers per year for the next four years and analyzing their energy savings compared to a control group.

COMMERCIAL PROGRAMS

1. Commercial & Industrial Prescriptive Incentive Program

The Commercial & Industrial prescriptive incentive program provides incentives to commercial and industrial consumers to install high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. This program will be jointly implemented with the Duke Energy Indiana and Duke Energy Kentucky territories to reduce administrative costs and leverage promotion. The current PSI program has been in effect for many years and promotes limited prescriptive incentives for motor, lighting and cooling equipment types. This application expands the program to include additional technologies covering more applications and end uses. This will allow more consumers to participate and avoid lost opportunities for high efficiency equipment in the marketplace.

School Incentive Program

Due to the special needs of schools and recognizing that saving energy costs in schools helps all taxpayers, Duke Energy Ohio and the DECP are proposing that $500,000 be set aside as part of the Commercial and Industrial Prescriptive Incentive Program budget for school measures and support. The measures identified for the Commercial and Industrial Prescriptive Incentive Program in this application can help schools reduce their energy consumption. Additional measures will be identified as Duke Energy Ohio works with the schools to assess energy saving opportunities. If all of the funds are not used by the schools within the year, they will be made available to other applicable commercial and industrial consumers. Likewise, if funds applicable to the Commercial and Industrial Prescriptive Incentive Program are not used by other commercial and industrial consumers, those funds will be made available to the schools above the earmarked amount.

The School Incentive Program provides incentives to schools to install high efficiency equipment in applications involving new construction, retrofit, and replacement of failed equipment. This program will be jointly implemented with the proposed Commercial and Industrial Prescriptive Incentive Program.

2. **Photovoltaic Schools Demonstration/Education Program**

This program was designed to introduce Photovoltaics ("PV") into the mix of options under Duke Energy Ohio's DSM program. It seeks to create awareness of the technical achievements, environmental considerations, and public policy issues that have matured to make photovoltaics an option for meeting today's energy needs. The program also focuses on educating faculty and students in the Ohio public school system about the benefits of photovoltaics as a source of renewable energy, through the installation and use of three PV demonstration units. This program has been successfully implemented in the Duke Energy Indiana territory.

RESEARCH PROGRAM

House Call PLUS Research Program

Opportunity: With rising energy prices, there is an opportunity to increase savings in the residential market through more comprehensive building analysis and efficiency improvements. As shown through state programs in New York and California, a comprehensive audit program, utilizing diagnostic tools such as blower doors, infrared scanners and duct leakage tests, combined with a "one-stop" installation service can be effective at getting more measures installed cost effectively, thus increasing savings from 10% to 30%. However to provide this service, the market providers such as insulation contractors and energy consultants, must learn how to effectively apply the building science, and how to use and apply the tools. The DECP sees this opportunity and wants to direct money towards research to better understand the current market capabilities and how this opportunity might effectively be implemented for consumers of Duke Energy Ohio.

Economic Impact of Smart Meter Project

Exhibit RGS 4
Corrected

Impact of Direct Investment

	Input-Output Multipliers Final-demand Output (dollars)	Components	Project Cost 20 Year Present Value	Total Economic Value	Incremental Value
Computer and electronic product manufacturing	2.1250	Hardware	$ 9,043,988	$ 19,218,475	$ 10,174,487
Electrical equipment and appliance manufacturin	1.9888	Equipment (1)	$ 428,032,179	$ 851,270,399	$ 423,238,219
Information and data processing services	2.0121	*Software and IT labor*	$ 26,333,978	$ 52,986,597	$ 26,652,619
Total			$ 463,410,146	$ 923,475,470	$ 460,065,325

Impact of Operational Direct Spending

	Input-Output Multipliers Final-demand Output (dollars)	Components	Project Cost 20 Year Present Value	Total Economic Value	Incremental Value
Utilities	1.3618	Power usage	$ 6,437,612	$ 8,766,741	$ 2,329,128
Computer and electronic product manufacturing	2.1250	Hardware and support	$ 13,408,335	$ 28,492,711	$ 15,084,377
Electrical equipment and appliance manufacturin	1.9888	Service contracts and maintenance	$ 31,644,787	$ 62,935,152	$ 31,290,365
Information and data processing services	2.0121	Software maintenance	$ 90,861,687	$ 182,822,800	$ 91,961,113
			$ 142,352,421	$ 283,017,404	$ 140,664,983

Total Project Costs, Economic Value and Incremental Value

		Project Cost 20 Year Present Value	Total Economic Value	Incremental Value
Capital		$ 463,410,146	$ 923,475,470	$ 460,065,325
Operation and Maintenance		$ 142,352,421	$ 283,017,404	$ 140,664,983
Total		$ 605,762,567	$ 1,206,492,875	$ 600,730,308
	Minimum Estimate	$ 605,762,567	824,927,463	$ 219,164,897
	Average Estimate			$ 409,947,602

(1) Meters, communication equipment, distribution automation equipment, and installation

UNSEALED 10/6/08

DE-OHIO EXHIBIT_____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan.	)))	Case No. 08-920-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Approval to Amend Accounting Methods	)))	Case No. 08-921-EL-AAM
In the Matter of the Application of Duke Energy Ohio for Approval of a Certificate of Public Convenience and Necessity to Establish an Unavoidable Capacity Charge	)))))	Case No. 08-922-EL-UNC
In the Matter of the Application of Duke Energy Ohio for Approval to Amend its Tariffs	)))	Case No. 08-923-EL-ATA

DIRECT TESTIMONY OF

CHRISTOPHER D. KIERGAN

ON BEHALF OF

DUKE ENERGY OHIO

July 31, 2008

234969

DE-OHIO EXHIBIT_____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan.	)))	Case No. 08-920-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Approval to Amend Accounting Methods	)))	Case No. 08-921-EL-AAM
In the Matter of the Application of Duke Energy Ohio for Approval of a Certificate of Public Convenience and Necessity to Establish an Unavoidable Capacity Charge	)))))	Case No. 08-922-EL-UNC
In the Matter of the Application of Duke Energy Ohio for Approval to Amend its Tariffs	)))	Case No. 08-923-EL-ATA

DIRECT TESTIMONY OF

CHRISTOPHER D. KIERGAN

ON BEHALF OF

DUKE ENERGY OHIO

July 31, 2008

234969

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Attachments:

CDK-1 Summary of Cost Benefit Study

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Christopher D. Kiergan. I am an Executive Consultant with KEMA, Inc. Established in 1927, KEMA is an international energy solutions firm providing technical and management consulting, systems integration, and training services to more than 500 electric industry clients in 70 countries. KEMA, with its North American operations headquartered in Burlington, Massachusetts, allows many of its consultants to be home-based when not physically at clients' locations; as such my business address is 1257 W. Wellington Ave., Chicago, IL 60657.

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

A. I graduated from the United States Naval Academy in 1983, with a Bachelor of Science in Mechanical Engineering. I served in the United States Navy as an officer and helicopter pilot (Search and Rescue, Antisubmarine Warfare, and Instructor). While in the Navy, I attended the Naval War College and earned a diploma in National Security and Strategic Studies. Upon completing ten years of active service, I attended the J.L. Kellogg Graduate School of Management at Northwestern University, graduating in 1995, with an MBA with majors in management and strategy, organizational behavior, and marketing. Upon graduation from business school, I entered the field of consulting with Booz Allen & Hamilton, performing operations and process reengineering consulting to manufacturers. Since leaving Booz Allen & Hamilton in 1997, I have worked for several consulting firms (joining KEMA in 2003), focused exclusively on providing consulting services and delivering solutions to utility clients, primarily electric utilities. I have experience on both strategy and operations engagements, which extends from corporate and business unit strategy to operational assessments and business process design. I have large project financial modeling and business transformation initiatives and performance improvement projects of back-office processes, supply chains, maintenance processes, and construction processes. Additionally, I have extensive experience with electric utility deregulation restructuring, leading two multi-year projects for western electric utilities.

Q. DOES KEMA HAVE RELEVANT EXPERIENCE WITH SMART GRID TECHNOLOGIES AND ADVANCED METERING INFRASTRUCTURE?

A. Yes. KEMA's Intelligent Networks and Communications (INC) market issue team is a worldwide leader in planning, designing, and implementing advanced communications, Advanced Metering Infrastructure (AMI), Distribution and Substation Automation, and infrastructure modernization systems. KEMA also provides project management experience to oversee the integration of these projects into utility operational systems. To date, KEMA's consultants have implemented numerous such projects and are presently supporting the implementation of some of the largest initiatives in North America, including programs for Duke Energy Corp. (Duke Energy), Con Edison, Southern California Edison, Public Service Electric & Gas, and Portland General Electric, as well as other Smart Metering or Smart Grid projects in Australia, Europe, and Brazil. KEMA has also previously assisted other key utilities in their automation programs, including Hawaiian Electric Company, Ketchikan Public Utilities, Benton County PUD, and Louisville Gas & Electric Company.

Within the INC market issue team, KEMA's Advanced Metering practice has established itself as a key partner for a number of the leading AMI programs in North America and in other global locales. The practice is comprised of both business strategists and technical specialists who together form a capability to understand all aspects of the business. With a rich combination of direct utility "hands on" experience, strong leadership and participation in industry consortia, and years of consulting project service, KEMA's consultants are well-versed in metering and communications technology, industry standards, regulatory/legislative trends, and the strategies and solutions of most of the leading suppliers. Using past and current AMI client engagements, KEMA has developed a library of knowledge regarding specific technology features, capabilities, and pricing, as well as insights into future product development efforts for most of the major North American providers.

In the area of distribution systems, KEMA offers broad and deep set of subject matter expertise in electric distribution system planning, design, and operations. KEMA has assisted numerous utilities with the assessment, procurement, and implementation of advanced technologies as well as business and operational strategies in this area. These include advanced field instrumentation, relay protection, equipment condition monitoring, feeder, distribution and substation automation, and information systems in support of planning, engineering, and operations.

Additionally, KEMA has extensive testing facilities in the Netherlands (Arnhem) and the United States, where it conducts testing of electrical equipment, from consumer products to high voltage electrical equipment. (In Europe, with regards to the electrical safety of products, KEMA is much like Underwriters Laboratory in the Unites States, providing the testing and certification of products, including the marking on consumer packaging.) In addition to testing electronic kWh and kVar meters on behalf of manufacturers worldwide, KEMA has recently set up a testing facility for Smart Grid technologies.

Q. PLEASE EXPLAIN KEMA'S SPECIFIC RESPONSIBILITIES RELATED TO THE DUKE ENERGY OHIO'S SMARTGRID INITIATIVE.

A. KEMA has been on-site with Duke Energy since December 2006, most recently helping to develop and refine the Company's business case and economic model for several jurisdictions, including Duke Energy Ohio (DE-Ohio), and assisting with vendor selection, quality assurance, and technology testing.

In 2007, KEMA was involved in developing and assessing the "use cases" put together by Duke Energy. The "use case" methodology was used to identify the services that Duke Energy would want to provide in the future and identify the benefits associated with the implementation of SmartGrid. This methodology pulled together both KEMA and Duke Energy Subject Matter Experts (SME) to create possible "uses" for SmartGrid, including, for example, "External Clients Use the AMI To Interact With Devices on the Customer Side," "Utility Remotely

Limits Energy Usage and/or Connects/Disconnects Customer," "Integrated Optimized Volt/VAR Control," and "Non-Dispatchable Distributed Generation." For each of the twenty-four uses or "use cases", individual teams described the uses in terms of the "actors" involved (individuals, companies, functional groups, specific equipment), assumptions, high-level requirements (business, functional, and non-functional), scenarios for use, and any issues specific to intended use.

KEMA has also been involved with the conceptual design and planning of the demonstration labs, as well as work on the deployment of meters and related equipment for the pilot programs in Ohio and the Carolinas.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS AN EXECUTIVE CONSULTANT FOR KEMA.

A. Since joining KEMA, I have worked onsite with utility clients on three long-term projects, providing management consulting services in the form of overall project management, process analysis and design, financial modeling, organizational design, and strategic planning. I spent two years at Cinergy Corp., assisting with the reengineering of the AFIC (After the Fact Interchange Costing) process mandated by the Joint Generation Dispatch Agreement (JGDA) signed in April 2002. In 2005, I began a two-and-a-half year project with the Bonneville Power Administration on an enterprise process improvement project that included current state assessments and analysis (including financial analysis), future state design, and implementation of solutions in several areas including supply chain, construction, and maintenance. Since the beginning of 2008, I have been with Duke Energy working on the SmartGrid cost/benefit model.

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

A. The purpose of my testimony is to support the cost/ benefit analysis of DE-Ohio's SmartGrid initiative. Specifically, I (1) describe the SmartGrid model; (2) explain how the model analyzes the program costs and benefits input into it; and (3) provide additional information on what specific costs and benefits were provided by DE-Ohio for input in the SmartGrid model. Finally, I sponsor Attachment CDK-1, which is a summary of the cost benefit analysis I performed for DE-Ohio's SmartGrid initiative in terms of inputs, assumptions, and results.

II. THE SMARTGRID MODEL

Q. PLEASE GENERALLY DESCRIBE THE SMARTGRID MODEL.

A. The SmartGrid model is a Microsoft Excel-based economic cost/benefit analytical model, which generally captures the overall economics, supports financial analyses and is used as a tool for management decisions for the SmartGrid project. It is a project-based model that shows capital expenditures, Operating and Maintenance expenses, and associated benefits for 2009-2028, and calculates an overall twenty-year net present value for the program. The SmartGrid model does not attempt to directly model the effect on rates, but the inputs and results are used as a basis for the calculation of rates and revenue requirement impacts.

Q. HOW WAS THE DE-OHIO SMARTGRID MODEL CREATED?

A. The Ohio SmartGrid model was created by DE-Ohio for an advanced metering infrastructure and SmartGrid pilot project in Ohio. However, over time, as additional costs and benefits were identified, as more-detailed analyses were performed in the areas of information technology, data transfer fees, distribution automation, and O&M expenses, and as SmartGrid technology and equipment considerations became more fully developed and costs became more firm, the model has been improved and is now a more detailed and more accurate depiction of the costs and benefits associated with the SmartGrid initiative in Ohio.

Q. PLEASE DESCRIBE THE INFORMATION INPUT INTO THE MODEL.

A. Generally, the model factors in seven primary categories of costs and five primary categories of benefits, in addition to general inputs and assumptions.

In the terms of costs, the categories are as follows:

- Endpoint Costs – This category is comprised of residential and commercial/industrial electric meters, electric meter bases, gas meters, communications modules for gas meters, and distribution line sensors. Data input in to the model includes the number of meters, timing of deployment, and costs of equipment. Additionally, power costs associated with operating the equipment and any ongoing operating costs or maintenance costs, including service contract costs, are included.
- Communications Costs – This category is comprised of the communications equipment used to collect and transmit the data from the field to DE-Ohio and includes data collectors and aggregators, integrated communications boxes (with and without gas data collectors), and stand-alone modems. Data input into the model includes the number of pieces of communications equipment, timing

of deployment, and costs of equipment. Additionally, power costs associated with operating the equipment and any ongoing operating costs, such as data transfer quantities and associated fees, or maintenance costs are included.

- Deployment Labor Costs – This category is comprised of the costs (calculated from hourly labor rates and estimated times to install) associated with installing the equipment listed in the Endpoint Costs and Communication Costs categories.
- Information Technology – This category is comprised of the hardware, software, labor, and outside consulting costs associated with the new systems and enhancements to existing systems required to implement the SmartGrid vision. (IT costs are calculated as Duke Energy-wide costs and allocated to the various jurisdictions in accordance with the Shared Services Company agreement.)
- Distribution Automation – This category is comprised of the costs (both labor and materials) associated with the distribution portion of the SmartGrid vision, including upgrading substation communications, replacing 12-kV reclosers with breakers, replacing the relays on 12-kV switchgear breakers, 12-kV outdoor breakers, and 34.5-kV outdoor breakers, installing communications functionality and controls on capacitor banks and electronic reclosers, changing out the controls on LTCs and regulators, sectionalizing the system with additional reclosers, and installing a minimum level of self-healing technology

- o Project Management Office (PMO) – This category 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. (PMO costs are calculated as Duke Energy-wide costs and allocated to the various jurisdictions in accordance with the Shared Services Company agreement.)
- o Additional O&M Costs – This category is comprised of those (O&M) costs not directly associated with the previously mentioned costs categories, and includes such items as additional labor for meter disposal, new equipment O&M labor, additional full-time employees to achieve power theft detection, and customer service (Call Center) O&M during the deployment to set-up ties to the billing system.

The aforementioned costs are then categorized as either capital or O&M. Capital costs include first time installation costs, equipment and labor costs to replace failures (based on individual equipment failure rates and warranty terms), and equipment and labor costs to replace equipment that has reached the end of its useful life (based on individual equipment useful life predictions). O&M costs are classified as operating costs, such as service contract costs and data transfer fees, and power costs associated with the power requirements of each new individual piece of equipment.

Benefits are categorized into five categories: Metering, Outage, Distribution, Other (includes Call Center, Vehicles, Safety), and Customer/Societal Benefits. An additional benefit, which is not quantified herein, is that the SmartGrid provides a broad platform for numerous energy efficiency programs. To calculate the value of these benefits, various inputs are needed, including current budget amounts for performing various activities (normal meter reading, meter orders, non-pay disconnects, outage assessment, equipment inspections, handling specific types of customer calls, etc.) and estimated, expected percentage savings.

The final group of data input into the model includes the assumptions and other model parameters. This list is extensive and includes: deployment timelines, meter growth rates, numbers of customers, service territory descriptive data (including numbers of pieces of equipment such as transformers, capacitor banks, etc.), financial assumptions (tax rates, depreciation rates, revenues, discount rate, inflation rates, load growth rates, loading costs), and timing of benefits. An additional category of assumptions are those items that are not included in the model, including the exclusion of corporate overheads and the exclusion of accelerated depreciation for removed meters (a request is expected to place these meters in a regulatory asset and depreciate as currently scheduled).

Q. **WHAT ARE THE SOURCES OF THE DATA INPUT INTO THE MODEL?**

A. KEMA obtained data from the applicable groups and employees within the Company through a detailed data request template. These groups included Power Delivery, Power Delivery Accounting, System Protection Engineering, Asset Management, Substations and Operations Maintenance, System Operations, Metering, Meter Operations, Meters and Infrastructure, Integrated Resource

Planning, Finance, Financial Forecasting, Accounting, Tax, IT, Customer Service, Billing, Energy Efficiency, Regulatory Strategy, and Rates. Follow-up discussions were held when necessary to clarify exactly what data was needed and the level of detail needed. Upon receiving this data, it was analyzed by me and others associated with the modeling process to verify the accuracy of the data in relation to predetermined, high-level estimates. For data that fell outside expectations, discussions and further analysis were conducted to confirm the accuracy of the data. Consensus was reached between me and the providers of data on all data entered into model. Additionally, in the areas associated with O&M costs, current budget amounts were checked with Power Delivery Accounting to ensure accurate and current data was being utilized.

Savings percentages (expected reductions in current budget amounts) associated with benefits were analyzed through a collaborative process including discussions with the affected groups and savings seen or projected in similar projects around the country.

Costs associated with new equipment (meters, communications, etc.) were obtained from the potential vendors of the equipment being considered for the SmartGrid project. This data was then reviewed to ensure that the costs modeled were the expected costs and not necessarily the current costs associated with small pilot programs or small purchase orders. These costs are best estimates since contracts for large purchases are not yet in place.

III. COST BENEFIT ANALYSES PERFORMED BY THE SMARTGRID MODEL

Q. PLEASE DESCRIBE HOW COST AND BENEFITS ARE ANALYZED BY THE SMARTGRID MODEL.

A. A project Net Present Value (NPV) was calculated based on the costs, benefits, and assumption input into the model. Benefits were calculated for each of the twenty years in the model (2009-2028) and treated the same whether they were a direct budget expense, an avoided cost, or an increase in revenue. (Benefits are placed into these categories to facilitate further analysis such as revenue recovery/rates calculations and overall O&M increase/decrease calculations, but they are all treated alike for purpose of the project NPV calculations.)

Overall costs are calculated on an annual basis and categorized as either O&M expenses or capital costs. Estimates of inflation are applied to some components such as labor and distribution automation materials. Inflation was not applied to other component costs which are expected to remain flat, such as metering equipment, communications equipment, and data transfer fees. On the capital costs, tax depreciation and book depreciation are calculated.

A useful financial measure, earnings before interest and taxes (EBIT), is calculated for the project by subtracting the incremental O&M expenses and the incremental tax depreciation costs from the SmartGrid benefits. Taxes (income and property) are applied to arrive at the After Tax Operating Income. Unlevered Free Cash Flow is then calculated by subtracting the Capital Expenditures and adding back the Tax Depreciation Costs to the After Tax Operating Income. The discount factor of 7.59625% is applied to the Unlevered Free Cash Flow to calculate the NPV.

There are some limitations in the model that should be explained. For example, to determine the overall NPV of the SmartGrid Initiative, the model treats all benefits the same, whether they be avoided costs, a budget decrease, or increased revenues. Also, project costs are included whether they are incremental to DE-Ohio or not, *e.g.*, project management labor may already be DE-Ohio employees that are just reassigned for the project. Additionally, the model also assumes a current day scenario for the next twenty years (with escalation and inflation) – it does not consider the impacts of future rate cases or other unforeseen changes to the operating environment. Finally, as a project economic model, this analysis does not directly give rate impacts or revenue requirements, though the results of the model are used as a basis for those calculations.

Q. WHAT TYPES OF BENEFITS WERE INCLUDED IN THE SMARTGRID MODEL?

A. Benefits captured in the model generally include:

- Metering Benefits
  - Reduction in regular meter reading costs
  - Reduction in meter order costs
  - Reduction in non-pay disconnect costs
  - Benefits of remote diagnostics – Reduction in costs associated with determining an issue is not a DE-Ohio issue without sending a crew to investigate
  - Increased revenue associated with a reduction in power theft
  - Benefits in meter operations, including reduced testing and refurbishment costs and a decrease in manual meter reading equipment and associated maintenance
  - Increased revenue associated with meter accuracy improvement
  - Increased revenue associated with salvaging replaced mechanical meters

- Outage Benfits
  - Reduced assessor labor costs associated with assessing outages

- Reduced crew time associated with assessing reenergization progress
- Incremental revenue associated with reduced outage durations

- Distribution Benefits
  - Avoided energy, capacity, and CO_2 costs associated with the voltage reduction strategy – system voltage control
  - Avoided energy, capacity, and CO_2 costs associated with power shortage voltage reduction
  - Decreased labor costs associated with continuous voltage monitoring
  - Avoided capacity costs associated with VAR management
  - Avoided capital costs associated with improved asset management (better data, optimized planning, etc.)
  - Avoided energy, capacity, and CO_2 costs associated with system fine-tuning resulting in a reduction in line losses
  - Decreased labor costs associated with capacitor inspections
  - Decreased labor costs associated with circuit breaker inspections

- Other Benefits
  - Decreased labor costs associated with a reduction in specific types of calls to the call center (Increased call center efficiency)
  - Increase in safety resulting in lower accident claims and lower workers' compensation insurance (associated with reduction in manual meter reading)
  - Increase in billing efficiency resulting in a reduction in estimated bills and a reductions in the number of bills that fail to go out on day one of the billing cycle
  - Reduction in vehicle capital costs and auto insurance expenses associated with meter reading vehicles

- Customer/Societal Benefits
  - Customer benefits associated with an increase in reliability
  - Avoided costs associated with plug-in hybrid electric vehicles (PHEVs)
  - Customer feedback (Prius effect) benefits
  - Macroeconomic impacts (multiplier effect)

Q. WHAT GENERAL CATEGORIES OF COSTS WERE INCLUDED IN THE SMARTGRID MODEL?

A. Cost components captured in the model include:

- Endpoint Equipment

- Cost of equipment (initial, based on failure rates, and based on end-of-useful life)
- Costs of meter base replacements
- Operating costs (Service Contracts)
- Power costs
- Warranty costs (if applicable)
- Data transfer requirements
- Depreciation lives
- Materials inflation rate
- Meter growth rates

- Communications Equipment
  - Cost of equipment (initial, based on failure rates, and based on end-of-useful life)
  - Operating costs (Service Contracts)
  - Power costs
  - Warranty costs (if applicable)
  - Data transfer requirements
  - Depreciation lives
  - Materials inflation rate
  - Meter and service territory equipment growth rates

- Deployment Labor
  - Installation costs (hourly rates)
  - Installation times
  - Labor inflation rates

- Information Technology
  - Hardware
  - Software
  - DE-Ohio labor
  - Outside consulting
  - O&M
  - Depreciation lives

- Distribution Automation
  - Substation communication upgrading (labor and materials)
  - Circuit breaker automation and relay replacement (labor and materials)
  - Regulator automation (labor and materials)
  - Capacitor bank/recloser automation (labor and materials)
  - Sectionalization (labor and materials)
  - Self-Healing technology (labor and materials)

- Project Management Office (PMO)
  - DE-Ohio labor (planning and deployment)

    - Consulting labor (planning and deployment)

- Other O&M Costs
    - New permanent personnel required with new communications equipment
    - Additional Power Delivery labor costs associated with O&M of new equipment
    - Additional labor costs associated with meter disposal
    - Additional IT maintenance costs associated with management tools and the central network
    - Network infrastructure support labor
    - Increased labor costs associated with power theft investigations
    - Increased labor costs associated with setting up new meters in billing

Q. PLEASE DESCRIBE ANY ADDITIONAL DATA USED IN THE MODEL.

A. In addition to the costs and benefits associated with the SmartGrid Initiative, the model also considers DE-Ohio service territory-specific data, specific financial assumptions, and relevant operating characteristics. These include:

- Deployment timelines for electric meters, gas meters, distribution automation, and information technology
- Meter growth rates (residential and commercial), both gas and electric
- Number of meters (all of Duke Energy)
- Number of consumers (all of Duke Energy)
- Storm level classification (number of storms, average duration, minimum and maximum number of consumers affected)
- Weighted average electricity rates
- Service territory data (number of square miles, circuits, overhead line, underground line, transformers, circuit breakers, capacitor banks, and reclosers)
- Residential and commercial electric revenues
- Residential and commercial gas revenues
- Discount rates
- Income tax rates (federal, state, local)
- Property tax rates
- Sales tax rates
- Book depreciation lives
- Tax depreciation lives and associated MACRS depreciation tables
- Property tax depreciation tables
- Debt rate

- Labor loading costs
- Electric rate price inflation rate
- Gas rate price inflation rate
- Residential and commercial electric growth rates (MWh)
- Residential and commercial gas growth rate (MCf)
- Inflation rates for each year of the twenty-year model (labor, materials, and blended)
- Benefit timing
- Monthly data transfer amounts (meters, capacitors, reclosers, aggregators)

Q. HOW IS THIS ADDITIONAL DATA USED BY THE MODEL?

A. This additional data is used to calculate benefits, costs, and NPV across the twenty years of the model.

Q. IS THE COST BENENFIT ANALYSIS SUMMARIZED IN THE ESP APPLICATION?

A. Yes. A Summary of the cost benefit analysis, including specific assumptions, inputs, and results, is included in the ESP Application at Part F.

Q. WAS THE COST BENEFIT ANALYSIS AT PART F PREPARED BY YOU AND UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. WHAT WERE THE RESULTS OF THE MODEL?

A. In terms of capital expenditures, $431.56 million is forecasted to be spent during the five-year deployment of 2009-2013. (2008 deployments are included in 2009 data). Over twenty years, capital expenditures are expected to rise to $715.13 million with a twenty-year NPV of $463.41 million.

In terms of benefits, $74.41 million is forecasted to be saved during the five-year deployment of 2009-2013. (2008 deployments are included in 2009 data). Over twenty years, savings are expected to rise to $840.66 million with a

20-year NPV of $353.01 million. (Benefits are less in the early years as many benefits are directly proportional to the amount of meters replaced or modules installed and several are dependent on longer information technology implementation schedules.)

In terms of O&M expenses, $51.65 million is forecasted to be spent during the five-year deployment of 2009-2013. (2008 deployments are included in 2009 data). Over twenty years, O&M expenses are expected to rise to $312.86 million with a twenty-year NPV of $142.35 million.

In terms of NPV for the cost/benefit model for the SmartGrid project, a twenty-year NPV of <$294.35 million> is calculated.

Offsetting this NPV are customer and societal benefits ranging from $380 million to $2.21 billion. Customer and societal benefits are wide-ranging due to the dependency on high-level industry estimates and studies.

Q. DID YOU PREPARE A MORE DETAILED ATTACHMENT CONTAINING THE COMPONENTS AND RESULTS OF YOUR MODEL?

A. Yes. Attachment CDK-1, which is filed under seal, contains additional details of the cost benefit model.

IV. <u>CONCLUSION</u>

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

A. Yes.

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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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	65,563
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)

SmartGrid Cost / Benefit Model – DE-Ohio

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.

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

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	$ 2,846,480
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	Year 2	Year 3	Year 4	Year 5
	2009	2010	2011	2012	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	Year 2	Year 3	Year 4	Year 5
	2009	2010	2011	2012	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

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 - 8.4% • 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 - 1.9868, 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 - 1.9868, 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
Benefit Utility of the Future	$	0.16	$	3.31	$	10.42	$	25.68	$	34.84	$	40.62	$	42.37	$	43.64	$	44.94	$	46.29
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
O&M expenses	$	3.66	$	8.43	$	12.48	$	13.16	$	13.91	$	14.23	$	14.67	$	15.10	$	15.55	$	16.00
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	$	3.96	$	4.09	$	4.21	$	4.35	$	4.48
Tax depreciation cost	$	4.43	$	19.96	$	26.66	$	30.44	$	29.62	$	27.79	$	25.12	$	23.52	$	22.03	$	21.47
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	$	2.67	$	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
EBIT	$	(7.93)	$	(20.08)	$	(26.03)	$	(17.82)	$	(8.68)	$	(1.40)	$	2.68	$	5.21	$	7.36	$	8.82
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
After-Tax Operating Income	$	(5.14)	$	(12.69)	$	(20.62)	$	(16.60)	$	(14.44)	$	(10.20)	$	(8.35)	$	(5.86)	$	(3.60)	$	(1.61)
Capital Expenditures	$	75.02	$	132.32	$	136.11	$	53.70	$	34.35	$	6.66	$	6.44	$	6.62	$	6.66	$	6.45
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	$	25.60	$	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	$	-	$	-	$	-	$	-
Unlevered free cash flow	$	(75.73)	$	(130.11)	$	(130.27)	$	(39.96)	$	(19.19)	$	10.92	$	10.43	$	10.98	$	11.87	$	11.21
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)																		

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	$ 47.68	$ 49.13	$ 50.63	$ 52.18	$ 53.78	$ 55.44	$ 57.16	$ 58.94	$ 60.78	$ 62.68
Metering	$ 25.51	$ 26.35	$ 27.20	$ 28.09	$ 29.00	$ 29.94	$ 30.91	$ 31.91	$ 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	$ 2.15	$ 2.21	$ 2.28	$ 2.35	$ 2.43	$ 2.50	$ 2.58	$ 2.66	$ 2.74	$ 2.83
O & M expenses	$ 16.44	$ 16.91	$ 17.37	$ 17.83	$ 18.31	$ 18.78	$ 19.27	$ 19.75	$ 20.25	$ 20.75
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
Tax depreciation cost	$ 22.22	$ 24.36	$ 27.43	$ 29.18	$ 29.68	$ 30.01	$ 30.62	$ 31.46	$ 32.07	$ 32.53
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
EBIT	$ 9.01	$ 7.87	$ 5.83	$ 5.17	$ 5.80	$ 6.65	$ 7.27	$ 7.74	$ 8.46	$ 9.41
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
After Tax Operating Income	$ (0.83)	$ (0.75)	$ (1.87)	$ (2.34)	$ (1.76)	$ (0.50)	$ 0.80	$ 1.93	$ 3.11	$ 4.38
Capital Expenditures	$ 28.70	$ 45.93	$ 44.67	$ 20.70	$ 14.46	$ 16.72	$ 22.34	$ 22.86	$ 16.42	$ 16.18
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
ıstallation / Deployment Labor Costs	$ 6.00	$ 10.67	$ 11.19	$ 4.95	$ 3.48	$ 5.02	$ 7.55	$ 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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Unlevered free cash flow	$ (7.31)	$ (22.32)	$ (19.10)	$ 6.18	$ 13.67	$ 12.79	$ 9.09	$ 10.52	$ 18.78	$ 20.73
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										

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
O & M expenses	$	51.65	$	312.86	$	142.35
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
Tax depreciation cost	$	105.40	$	514.86	$	241.91
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
EBIT	$	(82.64)	$	12.94	$	(31.25)
Income tax	$	(38.63)	$	(120.54)	$	(63.08)
Payment of property tax (lagging)	$	25.58	$	230.88	$	104.67
After-tax Operating Income	$	(69.59)	$	(97.39)	$	(72.85)
Capital expenditures	$	431.56	$	715.13	$	463.41
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
Unlevered free cash flow	$	(396.76)	$	(293.67)	$	(294.36)
Discount factor						
PV	$	(330.87)	$	(294.35)		
Cumulative NPV						
Real NPV						

Duke Energy

SmartGrid Cost / Benefit Model – DE-Ohio

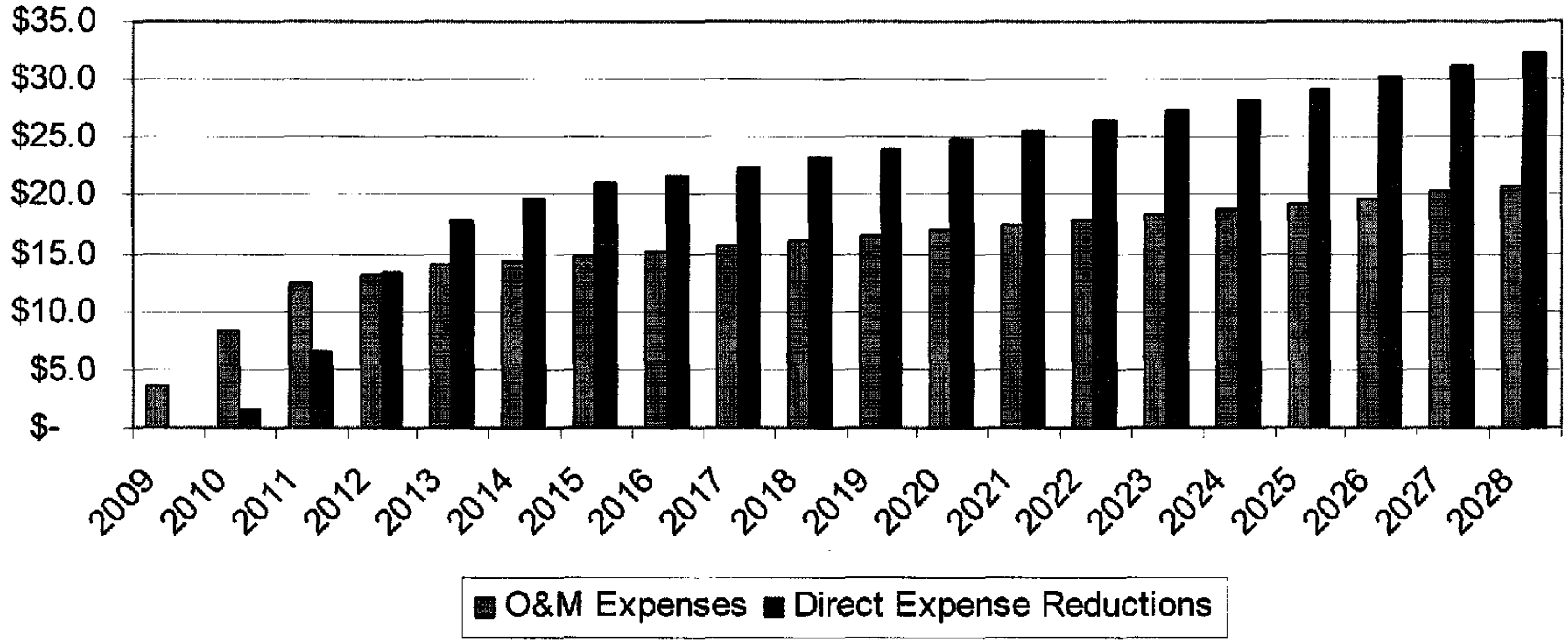
Capital and O&M versus Savings (millions)

Category	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	Year 11 2019
Capital Expenditures (millions)	$ 75.02	$ 132.37	$ 136.11	$ 53.70	$ 34.36	$ 6.66	$ 6.44	$ 6.52	$ 6.56	$ 8.45	$ 28.70
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 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	20-Year Total	20-Year NPV
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

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



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)

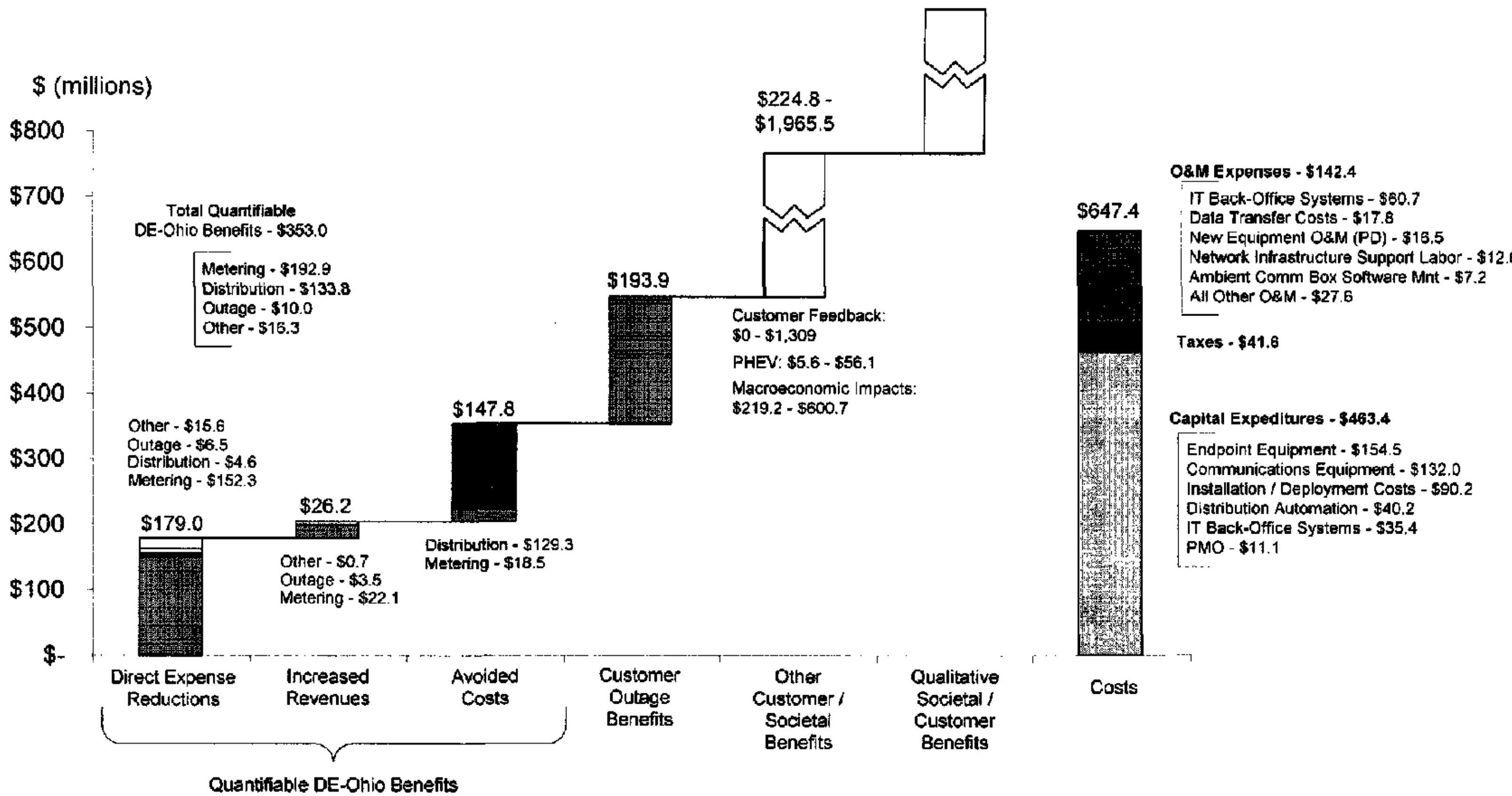
Benefit Category	Benefit	Savings Category	5-Year Total	20-Year Total	20-Year NPV
Metering	Regular meter reads	Direct Expense Reductions	$ 10.51	$ 151.99	$ 62.58
Metering	Off-cycle / off-season reads	Direct Expense Reductions	$ 19.54	$ 184.77	$ 78.31
Metering	Remote diagnostics (for individual customer 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)

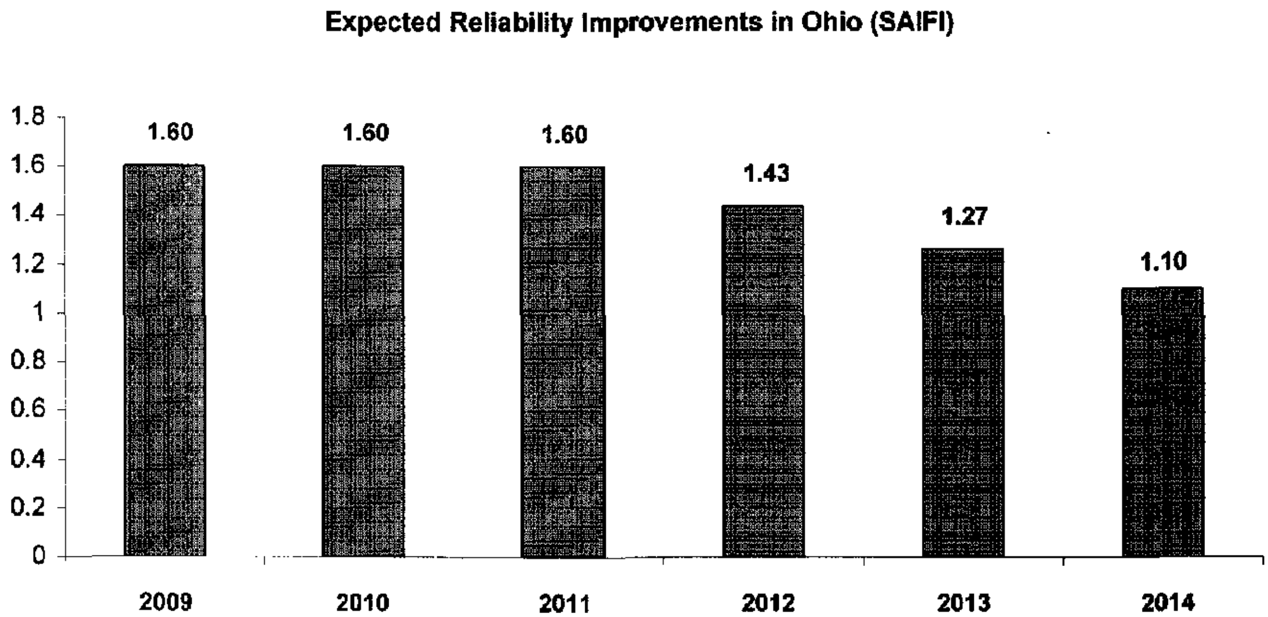
	Year 1 2009	Year 2 2010	Year 3 2011	Year 4 2012	Year 5 2013	5-Year Total	20-Year Total	20-Year NPV
Endpoint Ongoing Costs	$ 0.06	$ 0.25	$ 0.51	$ 0.68	$ 0.74	$ 2.26	$ 14.44	$ 6.61
Endpoint Power Cost	$ 0.03	$ 0.14	$ 0.27	$ 0.37	$ 0.42	$ 1.23	$ 9.41	$ 4.13
Comm Ongoing Costs	$ 0.45	$ 1.36	$ 2.36	$ 2.78	$ 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

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)



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	$ 781.66
Base Case[1]	[illegible]	[illegible]	[illegible]
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

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.

UNSEALED 10/6/08

DE-OHIO EXHIBIT _____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan	)))	Case No. 08-920-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Approval to Amend Accounting Methods	)))	Case No. 08-921-EL-AAM
In the Matter of the Application of Duke Energy Ohio for Approval of a Certificate of Public Convenience and Necessity to Establish an Unavoidable Capacity Charge	)))))	Case No. 08-922-EL-UNC
In the Matter of the Application of Duke Energy Ohio for Approval to Amend its Tariffs	)))	Case No. 08-923-EL-ATA

DIRECT TESTIMONY OF

RICHARD G. STEVIE, Ph.D.

ON BEHALF OF

DUKE ENERGY OHIO

July 31, 2008

233407

DE-OHIO EXHIBIT _____

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Attachments:

RGS-1 Load forecast for DE-Ohio

RGS-2 Annual reductions in load that must occur each year

RGS-3 Multipliers that represent the impacts on Final-demand Output

RGS-4 Four selected multipliers are provided along with the projected amounts of direct investments assigned to each of the four categories.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard G. Stevie. My business address is 139 E. Fourth Street, Cincinnati, Ohio.

Q: PLEASE STATE YOUR OCCUPATION.

A: I am Managing Director of Customer Market Analytics for Duke Energy Business Services, Inc. (DEBS), a wholly-owned service company subsidiary of Duke Energy Corporation (Duke Energy). DEBS provides various administrative services to Duke Energy Ohio, Inc. ("DE-Ohio") and other Duke Energy affiliates, including Duke Energy Indiana, Inc., Duke Energy Carolinas, LLC and Duke Energy Kentucky, Inc.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS MANAGING DIRECTOR OF THE CUSTOMER MARKET ANALYTICS DEPARTMENT.

A. I have responsibility for several functional areas including load forecasting, load research, demand side management (DSM) analysis, market research, load management analytics, and product development analytics. The Customer Market Analytics Department is responsible for providing functional analytical support to DE-Ohio as well as the other Duke Energy affiliates previously mentioned.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor's degree in Economics from Thomas More College in May 1971. In June 1973, I was awarded a Master of Arts degree in Economics from the University of Cincinnati. In August 1977, I received a Ph.D. in Economics from the University of Cincinnati.

My past employers include the Cincinnati Water Works where I was involved in developing a new rate schedule and forecasting revenues, the United States Environmental Protection Agency's Water Supply Research Division where I was involved in the research and development of a water utility simulation model and analysis of the economic impact of new drinking water standards, and the Economic Research Division of the Public Staff of the North Carolina Utilities Commission where I presented testimony in numerous utility rate cases involving natural gas, electric, telephone, and water and sewer utilities on several issues including rate of return, capital structure, and rate design. In addition, I was involved in the Public Staff's research effort and presentation of testimony regarding electric utility load forecasting. This included the development of electric load forecasts for the major electric utilities in North Carolina. I was also involved in research concerning cost curve estimation for electricity generation, rate setting and separation procedures in the telephone industry, and the implications of financial theory for capital structures, bond ratings, and dividend policy. In July 1981, I became the Director of the Economic Research Division of the Public Staff with the responsibility for the development and presentation of all testimony of the Division.

In November 1982, I joined the Load Forecast Section of The Cincinnati Gas & Electric Company (CG&E). My primary responsibility involved directing the development of CG&E's Electric and Gas Load Forecasts. I also participated in the economic evaluation of alternate load management plans and was involved in the development of CG&E's Integrated Resource Plan (IRP), which integrated the load forecast with generation options and demand-side options.

With the reorganization after the merger of CG&E and PSI Resources, Inc. in late 1994, I became Manager of Retail Market Analysis in the Corporate Planning Department of Cinergy Services, Inc. and subsequently General Manager of Market Analysis with responsibility for the load forecasting, load research, DSM impact evaluation, and market research functions of the combined Cinergy company. After the merger of Cinergy Corp. and Duke Energy in 2006, I became the General Manager of the Market Analysis Department with responsibility for several areas, including load forecasting, load research, market research, DSM strategy and analysis, load management development, and business development analytics. Since then, I have become the Managing Director of the Customer Market Analytics Department.

In addition, since 1990 I have chaired the Economic Advisory Committee for the Greater Cincinnati Chamber of Commerce. I have been a part-time faculty member of Thomas More College located in Northern Kentucky and the University of Cincinnati teaching undergraduate courses in economics. In addition, I am an outside adviser to the Applied Economics Research Institute in the Department of Economics at the University of Cincinnati as well as a member of an advisory committee to the Economics Department at Northern Kentucky University.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the American Economic Association, the National Association of Business Economists, and the Association of Energy Services Professionals.

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

A. My testimony explains: (1) the long term load forecast for DE-Ohio; (2) the evaluation process of DE-Ohio's energy efficiency program portfolio; (3) the DSMore model that DE-Ohio uses to evaluate energy efficiency programs; (4) the assumptions underlying the modeling; (5) the cost-effectiveness tests utilized; and (6) the results of these cost-effectiveness analyses. I then discuss DE-Ohio's proposed method of evaluating, measuring, and verifying the impacts achieved from its energy efficiency programs and a related issue on market transformation. My testimony also provides estimates of the broader economic benefits from the installation of smart metering systems. These are often referred to as the macroeconomic benefits or multiplier effects that arise from investments. My testimony will provide background on the method used to estimate the broader economic benefits and then apply the method to DE-Ohio's proposed investments in smart meter installations. Finally, I will also testify about an electronic bulletin board that will enhance supplier and customer participation in the competitive retail electric service market.

Q. PLEASE DESCRIBE THE ATTACHMENTS TO YOUR TESTIMONY.

A. Attachment RGS-1 provides the load forecast for DE-Ohio. Attachment RGS-2 provides information on the required level of energy efficiency required to meet the mandate set forth in R.C. Section 4928.66(A)(1)(a) (the "EE Mandate"), which is a cumulative 22% energy savings by 2025 based on the total, annual average, and normalized kilowatt-hour sales of the electric distribution company. Attachment RGS-3 provides the multipliers that represent the impacts on final-demand output. Finally, Attachment RGS-4 reflects the four selected multipliers applicable to the installation of a smart meter system which we refer to as SmartGrid.

II. DE-OHIO'S LOAD FORECAST

Q. DID YOU PARTICIPATE IN THE PREPARATION OF DE-OHIO'S LOAD FORECAST?

A. While I did not participate directly in the development of the forecast, the people who report to me did prepare the forecast. I have reviewed the projections and found them to be reasonable and appropriate for preparing the resource plan of DE-Ohio.

Q. HOW IS DUKE ENERGY OHIO'S LOAD FORECAST DEVELOPED?

A. The Load Forecast is developed in three steps: first, a service area economic forecast is obtained; next, an energy forecast is prepared; and finally, using the energy forecast, summer and winter peak demand forecasts are developed.

The forecast methodology is essentially the same as that presented in past Electric Long-Term Forecast Reports (LTFR) filed with PUCO, as well as the one filed as recently as April 15, 2008.

Q. PLEASE DESCRIBE HOW THE SERVICE AREA ECONOMIC FORECAST IS OBTAINED.

The economic forecast for the greater Cincinnati and northern Kentucky region is obtained from Moody's Economy.com, a nationally recognized economic forecasting firm. Based upon its forecast of the national economy, Moody's Economy.com prepares a forecast of key economic concepts specific to the greater Cincinnati area. This forecast provides detailed projections of employment, income, wages, industrial production, inflation, prices, and population. The information serves as input into the energy forecast models.

Q. HOW IS THE ENERGY FORECAST DEVELOPED?

A. The energy forecast projects the service area load required to serve Duke Energy Ohio's retail customer classes - residential, commercial, industrial, government or other public authority ("OPA"), and street lighting. The projected energy requirements for Duke Energy Ohio's retail electric customers are determined through econometric analysis. Econometric models are a means of representing economic behavior through the use of statistical methods, such as regression analysis.

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING ENERGY USAGE?

A. Some of the major factors are the number of residential customers, weather, and economic activity measures such as employment, industrial production, income and price. For the residential sector, the key factors are real per capita income, real energy price, weather, appliance saturations, and appliance efficiencies. For the commercial and governmental sectors, the key factors include the weather, employment, and real energy prices. In the industrial sector, the key factors include industrial production, real energy prices, and the weather. Finally, for the street lighting sector, the key factors include the number of residential customers and the saturation of efficient lighting.

Generally, energy use increases with higher industrial and commercial activity along with the increased saturation of residential appliances, including space heating and cooling equipment. As energy prices increase, energy usage tends to decrease due to customers' conservation activities.

Q. ARE THESE FACTORS RECOGNIZED IN THE EQUATIONS USED TO PROJECT THE ENERGY REQUIREMENTS OF DUKE ENERGY OHIO'S RETAIL CUSTOMERS?

A. Yes, they are. By including these variables in the forecasting process, we can project future energy consumption based on forecasts of these economic and weather factors.

Q. HOW IS THE FORECAST OF ENERGY REQUIREMENTS FOR DUKE ENERGY OHIO'S RETAIL CUSTOMERS PREPARED?

A. The DE-Ohio forecast of energy requirements is included within the overall forecast of energy requirements for the greater Cincinnati and northern Kentucky region. The DE-Ohio sales forecast is developed by allocating percentages of the total regional forecast for each customer group. These percentages provide DE-Ohio forecasts for sales to the residential, commercial, industrial, government or OPA, and street lighting sectors. Forecasts are also prepared for three minor categories: interdepartmental use (Gas Department), Company use (Duke Energy Ohio), and losses. In a similar fashion, the DE-Ohio peak load forecast is developed by allocating a share from the regional total. Historical percentages and judgment are used to develop the allocations of sales and peak demands.

Q. PLEASE EXPLAIN HOW THE PEAK FORECASTS ARE DEVELOPED.

A. DE-Ohio projects both a winter and a summer peak for the total region using econometric equations where peak demand is a function of economic growth, as measured by energy sales, and several key weather factors. As previously discussed, the DE-Ohio peak load forecast is developed by allocating a share from the regional total.

For the summer peak, the weather factors are temperature and humidity around the time of the peak, the morning low temperature, and the high temperature for the day before the peak. For the winter peak, the weather factors are the temperature and wind speed around the time of the peak, and the low temperature from the evening before when the peak occurs in the morning. If the winter peak occurs in the evening, the morning low temperature for the day is used instead of the evening low from the day before.

Q. IS DE-OHIO'S LOAD FORECASTING METHODOLOGY SIMILAR TO THAT EMPLOYED PRIOR TO THE CREATION OF DUKE ENERGY IN 2006?

A. Yes, the econometric forecasting methodology used to create the Load Forecast is basically the same as that used by DE-Ohio prior to the merger. As previously mentioned, the forecast is the same as that filed with the Commission in the 2008 Long-Term Forecast Report.

Q. ARE YOU FAMILIAR WITH OTHER ELECTRIC UTILITIES' LONG-TERM LOAD FORECASTS?

A. Yes, I am.

Q. ARE THE FACTORS THAT ARE USED BY DE-OHIO IN FORMULATING ITS LOAD FORECASTS SIMILAR TO THE FACTORS USED BY OTHER UTILITIES IN THEIR LOAD FORECASTS?

A. Yes. While other utilities might use a variety of load forecasting approaches, such as econometric, end-use, trend analysis, or time series analysis, nearly all of the utilities I am familiar with use the same factors considered by DE-Ohio, to varying degrees. These commonly used factors include: population, weather data, income forecasts, industrial production measures, employment, and price information. In addition, price forecasts for alternate fuels including natural gas and fuel oil are used as well.

Q. DOES DE-OHIO'S ENERGY AND PEAK LOAD FORECAST ALREADY INCLUDE THE IMPACT OF HISTORICAL DEMAND SIDE MANAGEMENT PROGRAMS?

A. Yes, the impacts of the historical demand side management (DSM) programs that have been implemented in the DE-Ohio service area are already reflected in these forecasts. The historical data used to develop the 2008 Load Forecast incorporate the impact of those existing programs.

Q. ARE THERE OTHER PEAK LOAD REDUCTIONS THAT ARE NOT INCLUDED IN DE-OHIO'S LOAD FORECAST?

A. Yes. The peak load reductions attributable to the Power Manager and PowerShare® CallOption program are not reflected in DE-Ohio's load forecast. In addition, the incremental load reductions expected from energy efficiency conservation programs have also not been reflected in the forecast.

Q. ARE THERE ANY ADJUSTMENTS MADE TO THE FORECASTS DERIVED FROM THE ECONOMETRIC MODELS?

A. Yes, the forecast includes a specific adjustment to account for the impacts of the new federal energy efficiency legislation, the Energy Independence and Security Act of 2007 ("EISA"), dealing with lighting standards that goes into effect 2012. Attachment RGS-1 provides the load forecast for DE-Ohio after incorporating the impacts from the EISA legislation.

Q. DOES THE RECENT PASSAGE OF AMENDED SUBSTITUTE SENATE BILL 221 AFFECT DE-OHIO'S LOAD FORECAST?

A. Yes. The energy efficiency mandates of Amended Substitute Senate Bill 221 (SB 221) could have a significant impact on the load forecast. Based on the percentages as stated in the legislation and a three year rolling average of DE-Ohio energy and peak loads, DE-Ohio has estimated the required annual reductions in load that must occur each year. Attachment RGS-2 provides these estimates. The calculations include a credit for energy efficiency and demand response impacts already achieved by DE-Ohio since 1998. It must be emphasized that while these load reductions represent the levels required to meet the conditions in the legislation, they may not be cost-effective or achievable. DE-Ohio has commissioned a market potential study to ascertain the level that can be achieved. Unfortunately, this study is still in process. Results will be incorporated in future filings.

III. DE-OHIO'S ENERGY EFFICIENCY PROGRAMS

Q. HOW WERE DUKE ENERGY OHIO'S ENERGY EFFICIENCY PROGRAMS DEVELOPED?

A: As explained in the testimony of Company Witness Schultz, DE-Ohio has been working to re-design its portfolio of programs in collaboration with interested stakeholders (the "Collaborative") over the past several years. The energy efficiency[1] programs and measures considered by DE-Ohio included (i) programs already offered and tested by DE-Ohio's affiliated utility operating companies, (ii) any new programs suggested by the Collaborative over the years, and (iii) existing programs offered by DE-Ohio. DE-Ohio is in the process of analyzing each potential program. DE-Ohio will apply multiple cost-effectiveness tests to determine a final set of energy efficiency programs. The programs being filed for inclusion in DE-Ohio's Energy Efficiency Plan and Rider DR-SAW are the existing portfolio of programs and the PowerShare program described in DE-Ohio witness Schultz's testimony in this docket.

Q. HAS DE-OHIO COMPLETED A MARKET POTENTIAL STUDY ON ENERGY EFFICIENCY PROGRAM POTENTIAL?

A. As mentioned above, DE-Ohio has not yet completed a market potential study. DE-Ohio has commissioned a market potential study, but the results of this study are not yet available. Once that study is complete, the results will be compared

[1] The term "energy efficiency," as used in this testimony, includes both energy efficiency/conservation and demand response measures.

with the programs previously developed through the Collaborative process and additional program offerings may be filed for approval with the Commission, as appropriate.

Q. WHAT IS THE PURPOSE OF A MARKET POTENTIAL STUDY?

A. The purpose of a market potential study is to provide estimates of the market potential for energy efficiency for DE-Ohio's customers. The study provides estimates of the technical, economic, and market potentials for energy efficiency. The technical potential is defined as the amount of energy efficiency that could be obtained if all energy efficiency measures were adopted without regard to costs. This level of savings represents the upper limit of energy efficiency opportunity.

The economic potential is defined as the total energy savings available at a specified long-term avoided cost of energy. Measures with levelized costs that are lower than the avoided cost of energy are included in estimates of economic potential. The market potential is defined as the total energy savings available from all programs recommended in the market potential study, considering cost-effectiveness and adoption rates.

IV. THE DSMore MODEL

Q. WHAT IS THE DSMore MODEL?

A. DSMore is a financial analysis tool designed to evaluate the costs, benefits, and risks of energy efficiency programs and measures. DSMore estimates the value of an energy efficiency measure at an hourly level across distributions of weather and/or energy costs or prices. By examining energy efficiency performance and cost effectiveness over a wide variety of weather and cost conditions, DE-Ohio is in a better position to measure the risks and benefits of employing energy efficiency measures versus traditional generation capacity additions, and further, to ensure that demand-side resources are compared to supply-side resources on a level playing field.

The analysis of energy efficiency cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test ("UCT"), Ratepayer Impact Measure ("RIM") Test, Total Resource Cost ("TRC") Test, Participant Test, and Societal Test. DSMore provides the results of those tests for any type of energy efficiency program (demand response and/or energy saving).

The test results are also provided for a range of weather conditions, including normal weather, and under various cost and market price conditions. Because DSMore is designed to be able to analyze extreme conditions, one can obtain a distribution of cost-effectiveness outcomes or expectations. Avoided costs for energy efficiency tend to increase with increasing market prices and/or more extreme weather conditions due to the covariance between load and costs/prices. Understanding the manner in which energy efficiency cost effectiveness varies under these conditions allows a more precise valuation of energy efficiency programs and demand response programs.

Generally, the DSMore model requires the user to input specific information regarding the energy efficiency measure or program to be analyzed as well as the cost and rate information of the utility. These inputs enable one to then analyze the cost-effectiveness of the measure or program.

Q. WHAT ENERGY EFFICIENCY PROGRAM OR MEASURE INFORMATION IS INPUT INTO THE MODEL?

A. The information required on an energy efficiency program or measure includes, but is not limited to:

- Number of program participants, including free ridership or free drivers;
- Projected program costs, contractor costs and/or administration;
- Customer incentives, demand response credits or other incentives;
- Measure life, incremental customer costs and/or annual maintenance costs;
- Load impacts (kWh, kW and the hourly timing of reductions); and
- Hours of interruption, magnitude of load reductions or load floors.

Q. WHAT UTILITY INFORMATION IS INPUT INTO THE MODEL?

A. The utility information required for the model includes, but is not limited to:

- Discount rate;
- Loss ratio, either for annual average losses or peak losses;
- Rate structure, or tariff appropriate for a given customer class;
- Avoided costs of energy, capacity, transmission & distribution; and
- Cost escalators.

Q. WHAT PROCESS DOES DE-OHIO FOLLOW TO EVALUATE THE PROGRAMS OR MEASURES?

A. To begin, an analyst or program manager develops the inputs for the program or measure using information on expected program costs, load impacts, customer incentives necessary to drive customers' participation, free rider expectations, and expected number of participants. This information is used in initial runs of the model to determine cost-effectiveness and whether adjustments need to be made to a program or measure in order for it to pass the participant test, the first critical test.

Then, the load impacts of the program or measure may be analyzed as a percent of savings reduction from the current level of use, as proportional to the load shape for the customer, or as an hourly reduction in kWh and/or kW. These approaches apply to energy saving programs and measures. For demand response programs, the analyst must provide information on the amount of the expected load reduction and the possible timing of the reduction.

This is the typical process DE-Ohio employs to evaluate programs and measures.

Q. WHAT IS THE SOURCE OF THE DATA FOR THE PROGRAM OR MEASURE?

A. Program managers and analysts develop the inputs for each program or measure from industry information derived from sources such as Electric Power Research Institute (EPRI), Energy Star, E-Source, other utility program information, as well as from external experts in the industry. Over time, as impact and process evaluations are performed on Ohio program results, information and input specifically related to Ohio customers will begin to emerge and be used within future cost effectiveness analyses.

Q. WHAT IS THE SOURCE FOR THE UTILITY INPUTS TO THE MODEL?

A. The discount rate is obtained from DE-Ohio's most recent cost of capital analysis, losses are based upon past experience of DE-Ohio, rate structures are based on the current Company's tariffs, avoided transmission and distribution costs are obtained from DE-Ohio's most recent analysis of incremental transmission and distribution capital spending, relative to load growth forecasts, and avoided energy and capacity costs are based upon market prices, which are the subject of Witness Judah Rose in this proceeding. In the long-run, avoided capacity costs should trend toward the cost of new capacity. Estimates of the long-term capacity costs are the subject of a recent request for proposal (RFP) issued by DE-Ohio which is included in this application at part C. At this time, the results of the RFP are not available. DE-Ohio intends to use that information, once available, in conjunction with the market estimates from its consultant, ICF, to develop a long-run projected avoided capacity cost.

Program specific inputs include items such as program costs, measure life, free ridership, incremental customer costs, energy savings, demand savings, and marketing or distribution costs.

The ultimate test of energy efficiency cost-effectiveness lies in integrated resource plan (IRP) model run comparisons with and without the energy efficiency programs inserted as resource options. An up-front energy efficiency screening process is still necessary, though, because IRP production costing models are unable to accommodate the hundreds of analyses required for measure-specific energy efficiency resource options within its optimization modeling framework. So, pre-screening and bundling of energy efficiency options that are found to be cost-effective is a more efficient and effective approach.

For the generation analysis in this filing, DE-Ohio has assumed the energy efficiency mandate level of energy savings within the IRP. Comparing the energy costs from an IRP with the energy efficiency impacts to one without the energy efficiency impacts provides the best overall estimate of the avoided energy costs that also embodies any base load and intermediate avoided capacity costs not captured in the peaker capacity cost. This approach and analysis will be conducted annually, to ensure that the estimation and valuation of avoided energy costs is consistent with DE-Ohio's alternative supply side resources, and with forward expectations of avoided energy costs.

V. COST-EFFECTIVENESS TESTS

Q. PLEASE DESCRIBE HOW ENERGY EFFICIENCY PROGRAMS AND MEASURES ARE ANALYZED.

A. Once programs and measures have been analyzed using DSMore, the net present value of the financial stream of costs versus benefits are assessed, *i.e.*, the costs to implement the measures are valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected load impacts. As previously mentioned, the Participant Test is the first screen for a program or measure to make sure a program makes economic sense for the individual consumer. DE-Ohio also uses the Utility Cost Test ("UCT"), the Total Resource Cost Test ("TRC"), and the Ratepayer Impact Test ("RIM") Test for screening energy efficiency measures.

- The Participant Test compares the benefits to the participant through bill savings and incentives from the utility, relative to the costs to the participant for implementing the energy efficiency measure. The costs can include capital cost as well as increased annual operating cost, if applicable.

- The UCT compares utility benefits (avoided costs) to incurred utility costs to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The TRC test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

The use of multiple tests can ensure the development of a reasonable set of energy efficiency programs, indicate the likelihood that customers will participate, and also protect against cross-subsidization. It should also be noted that none of the tests described above include external benefits to participants and non-participants that can also offset the costs of the programs.

Q. WHAT WERE THE RESULTS OF THE PROGRAM ANALYSIS?

A. The test results for the programs listed in DE-Ohio witness Schultz's testimony were previously provided to the Commission in DE-Ohio's 2006 Application for Recovery of Costs, Lost Margin, and Performance Incentive Associated with the Implementation of Electric Residential Demand Side Management Programs in Case No. 06-91-EL-UNC. Test results for DE-Ohio's new portfolio of programs are not available at this time, but will be completed after the information on avoided capacity costs has been fully developed.

VI. <u>MEASUREMENT AND VERIFICATION</u>

Q. WHY IS EVALUATION, MEASUREMENT AND VERFICATION A CRITICAL COMPONENT OF DE-OHIO ENERGY EFFICIENCY PLAN?

A. DE-Ohio believes that successful, reliable and cost-effective energy efficiency programs require valid evaluation, measurement and verification (EM&V) activities to: (1) assure that measures are installed and tracked properly; (2)

verify or revise energy impacts; (3) monitor and ensure customer satisfaction; and (4) establish independent third-party evaluations and reviews to confirm energy impacts and to improve program delivery, efficiency and effectiveness.

DE-Ohio has historically conducted such studies on its programs and will continue to do so for any new programs.

Q. WHAT IS MEASUREMENT AND VERIFICATION?

A. Measurement and verification (M&V) of energy efficiency programs and measures is an umbrella term (sometimes referred to as EM&V). There are five types of evaluation, in general. First, there is cost effectiveness evaluation, which I discussed above. Second, impact evaluation strives to estimate the actual energy and demand load reductions realized from a program. Third, measurement typically refers to the metering, sub-metering, hours-use logger meter, statistical pre- and post-analyses, or other modes of measuring load reduction. Usually, measurement is a subset of an impact evaluation. Fourth, verification refers to the confirmation that customers actually installed the intended measures, that vendors are performing to expectation and that operational factors on the customer site are occurring such that the expected load savings can be realized. Finally, process evaluation refers to a set of review and auditing methods that ascertain program effectiveness, efficiency, customer satisfaction, vendor satisfaction and other factors that contribute to program success.

Q. HOW DOES DE-OHIO PLAN TO MEASURE, MONITOR AND VERIFY THE PROGRAMS?

A. In general, the following approach will be used for monitoring and verification of programs:

Paper and Electronic Verification

- Paper or electronic verification will be completed on all applications for energy efficiency incentives by customers. As part of the application process, specific customer and measure data will be requested from applicants. Data requested will vary depending on the program, the measure, the equipment and the delivery of the application. Customers and/or contractors will be contacted for clarification and completion of the application if they fail to provide necessary information. Incentives will only be processed once verification is complete and information is entered into the electronic tracking systems. Verification information and all customer applications for incentives will be maintained by DE-Ohio.

Field Verification and Monitoring

- In most cases, will occur on customer premises using randomly selected samples of approximately 5% of installations. On-site visits will verify the installation of the claimed equipment in the proper application, confirm appropriate contractor or vendor processes and performance, and bring to light potential discrepancies or process improvements for the programs. Sample size will be larger for very large projects with significant incentives or energy impacts at risk. The size of such samples will be commensurate with the increased load savings as determined by DE-Ohio. Field training and support will be given to auditors performing assessments, to ensure quality both for communications and technical capabilities.

Customer Satisfaction Surveys

- Customer satisfaction surveys will be utilized to monitor satisfaction with program delivery and design, seek additional improvements to the program, and potentially uncover latent problems or issues with the measure/installation.

System Performance Tests

- System performance tests for load control resources will be conducted periodically to ensure that operational systems are working correctly, and that the projected load reductions are reliably available when needed. Load research metering samples and tracking will also be used to verify energy reductions.

If a problem is found with the installations or operations, the contractor and customer will be notified for correction. In addition, subsequent work or projects performed by that contractor will be monitored until DE-Ohio is satisfied that the installations or projects are being completed according to program specifications and operational standards. If the problems are not resolved to the satisfaction of DE-Ohio, that contractor, at DE-Ohio's discretion, may be eliminated from the program.

After the final set of programs has been fully developed, DE-Ohio will provide for the independent review and evaluation of its proposed programs by establishing initial evaluation plan summaries that propose specific energy efficiency evaluation studies and activities that will be competitively bid, designed, managed, supervised or conducted by independent and qualified evaluation professionals.

Evaluation studies will generally include methods such as loggers to capture appliance usage times, load research metering for hourly load analysis, statistical pre- and post-billing analysis using comparison control groups, engineering analysis and modeling, reference and comparisons to impact studies conducted in other regions for similar programs, phone and online interviews, and other methods reviewed within the International Performance Measurement and Verification Protocols, the California Evaluation Framework, and the Model Energy Efficiency Program Impact Evaluation Guide prepared as part of the National Action Plan for Energy Efficiency.

Q. WHAT IS THE ESTIMATED COST AND TIME FRAME FOR THE EVALUATION, MONITORING AND VERIFICATION?

A. DE-Ohio estimates that 5% of total program costs will be required to adequately and efficiently perform evaluations, monitoring and verification. The industry standard for evaluation costs is typically 3% to 5% of total program spending. However, DE-Ohio is prepared to increase the level of spending as necessary to obtain reliable estimates of the load impacts from the programs.

Q. HOW WILL THE EVALUATION, MEASUREMENT, AND VERIFICATION RESULTS BE UTILIZED IN DE-OHIO'S RECONCILIATION AND TRUE-UP PROCESS FOR THE PROPOSED RIDER?

A. The EM&V process produces results on two main concepts: actual customer participation and actual load impacts. The reason these are important to the reconciliation and true-up process is that the original evaluation of program cost-effectiveness utilized projected numbers for participants in the programs and estimates of the load impacts. The EM&V process provides actual values to develop the estimates of the true-up.

It would be helpful if the timing on availability of the actual participation and load impacts coincided. Unfortunately, that is not the case. Information on actual participation and verification of installments are available more quickly because both can be collected as the program is rolling out. However, information on load impacts is more complex and tends to require rigorous impact evaluation studies, statistical billing analyses of pre- and post-usages, participant and non-participant surveys, and related activities that take time and care to complete in order to produce unbiased estimates of the load impacts. To do this, DE-Ohio must first wait several months to see how many participants there are in a particular measure in order to establish the sample size needed. Second, DE-Ohio must wait to collect post-installation load information, because a measure has to be installed for a reasonable period of time before DE-Ohio can estimate the level of load impact. During this process additional information will be collected on free-riders and free-drivers to adjust the level of the load impacts, where necessary.

The timing of the availability of participant and load impact results has implications for the reconciliation and true-up process. I expect that for the first true-up process, DE-Ohio will have actual participant information and possibly some load impact results, most likely for demand response programs (unless the timing of the true-up filing is during or immediately after the summer period). Load impact results for all programs will not be available until the completion of the second year of program implementation. At that point, a true-up of load impacts can be undertaken from the beginning of the program through the second year.

In general, DE-Ohio anticipates that the participant results will be reconciled each year and load impact results every other year. However, updates to the load impact results would only be reconciled back to the previous impact evaluation, not to the beginning of the program.

In working through the EM&V process, it is important to note that DE-Ohio has a strong incentive to have these studies completed in as timely a manner as possible. Besides being at risk for results under the save-a-watt approach, DE-Ohio needs to know quickly if these programs work in order to make sure the long-term generation plan is not affected. I will add that the complexity of the EM&V process is not the result of the structure of any specific regulatory recovery mechanism; rather, it is the nature of energy efficiency programs in general. Reliable measurement and verification of energy efficiency impacts requires time. To the extent that the Commission prefers stability and simplicity in the estimation and implementation of the rider for energy efficiency cost recovery, it is possible to stipulate the load impacts for the period of one year, or until such time as a complete impact evaluation has been conducted, at which time any required change in the impacts can be applied going forward, but not affect a retrospective true-up.

VII. MARKET TRANSFORMATION

Q. PLEASE DESCRIBE HOW THE EM&V ANALYSIS WILL REFLECT CHANGES IN THE MARKET AND PARTICIPANT BEHAVIOR OVER TIME.

A. Evaluation, measurement and verification will be conducted over time to verify the magnitude and persistence of the energy efficiency impacts achieved from both program participants, as well as from non-participants. Over time, DE-Ohio's energy efficiency programs can affect the nature of the energy efficiency market such that customer behavior, vendor behavior, and even manufacturer behavior is altered. Where significant momentum is generated with respect to the adoption of increased energy efficiency, it is possible to transform markets such that customers begin to demand more energy efficiency from their vendors, equipment providers, and manufacturers. This increased demand for energy efficiency can occur from "word of mouth" interactions as well as customer exposure to DE-Ohio's advertising and promotion of energy efficiency or the result of distribution channel partnerships between DE-Ohio and networked trade allies or manufacturers.

Importantly, partnership arrangements and distribution networks that DE-Ohio structures to deliver more efficient equipment have an impact both on customers that are aware of DE-Ohio's efforts as well as those that are not. In either case, energy efficiency is likely to be adopted, but the more that DE-Ohio is able to move these markets toward more efficient choices for customers, the more cost effective is DE-Ohio's realization of efficiency gains. In other words, factors such as these can drive more customers to implement energy efficiency measures without actually receiving the DE-Ohio's incentives offered. This results in a transformation of the market that would not have occurred without the actions or interventions in the market by DE-Ohio. This market mechanism is often referred to as free driver behaviors, or sometimes labeled as spillover effects, in contrast to the more familiar concept of free ridership.

Free riders are those customers who receive an incentive but would have purchased the energy efficiency equipment even without the incentive, whereas free drivers are those customers who purchase energy efficient equipment without an incentive as a result of market transformation. Both market phenomena matter in the prudent pursuit of demand-side resources and integrated resource planning. As such, DE-Ohio intends to measure both free rider and free driver impacts to more accurately gauge the overall cost-effectiveness of its energy efficiency efforts. For DE-Ohio's cost-effectiveness analyses discussed here, DE-Ohio intends to include the impacts of free riders, but not free drivers.

Q. HOW WILL THESE IMPACTS BE IDENTIFIED?

A. These market phenomena will be measured through the EM&V process. Free ridership will be measured through customer surveys, statistical billing analysis, pre- and post- measurement processes and related studies among program participants, whereas free driver impacts will be measured among non-participant customer populations and/or through analysis of manufacturing trends and vendor surveys, or other types of analyses that are able to discern the influence and contribution of these market effects on the adoption of energy efficiency measures and behaviors.

VIII. METHOD FOR ESTIMATING ECONOMIC BENEFITS

Q. WHAT METHOD IS USED TO ESTIMATE THE ECONOMIC BENFITS FROM INVESTMENTS?

A. In general, investments made for a project have direct and indirect / induced types of impact. The direct impacts are measured by the installation phase of the project as well as on-going operational expenditures. The installation phase represents the capital equipment and the labor dollars to complete the construction phase of the project. Beyond the initial completion of the construction phase, there is the direct spending from on-going operations.

The indirect economic impacts arise in the form of increased income generated due to the increase in economic activity from the direct spending. In other words, the direct spending creates a "ripple" effect or induced impact above and beyond the direct spending. The total economic impact will be some multiple of the direct spending.

One way to look at this is if a business spends an additional dollar on a project, that dollar is spent, in part, again by the person or business that received it. This process repeats itself again and again until the cycle of spending is exhausted. The total economic impact can sometimes be many multiples of the initial dollars spent.

The general method for conducting this analysis involves the use of Input-Output multipliers to estimate the total economic impact of increases in final demand for goods and services. Input-Output analysis was developed by Wassily Leontief in the late 1930's and early 1940's as a way to model the interrelationships among the components of the economy. Through an Input-Output matrix, one can gain an understanding of the impact of a change in the level of activity in one industry on other supporting industries. Input-Output model coefficients provide the estimates of the impacts from these interrelationships. The approach has been used since the 1970's by the Bureau of Economic Analysis, Department of Commerce, to provide a structure for conducting estimates of the economic benefits from projects.

Q. HOW IS THE INPUT-OUTPUT METHOD APPLIED TO ESTIMATE ECONOMIC IMPACTS?

A. The Bureau of Economic Analysis (BEA) has developed a set of regional multipliers known as RIMS II (Regional Input-Output Modeling System). The BEA has created multipliers for the impact on final-demand output, final-demand earnings, final-demand value-added, direct-effect earnings, and direct-effect employment. The estimates of multipliers can be obtained for the nation as a whole as well as for specific regions. The BEA has developed a set of multipliers for the Greater Cincinnati region. DE-Ohio has obtained the set of multipliers in order to estimate the broader economic impacts from the smart meter project. Attachment RGS-3 provides the multipliers that represent the impacts on Final-demand Output. The values represent the total dollar change in output that occurs across all industries for each dollar of output delivered to final demand by the row industry. These multipliers can be used with the projected level of direct spending to estimate the total economic impact.

From the multipliers in Attachment RGS-3, I selected four that are applicable to the installation of a smart meter system. These are Utilities, Computer and Electronic Product Manufacturing, Electrical Equipment and Appliance Manufacturing, and Information and Data Processing Services. The four selected multipliers are provided on Attachment RGS-4 along with the projected amounts of direct investments assigned to each of the four categories. The associated levels of on-going spending are also provided.

The present value total direct investment of the project is $ 463 million. Using the multipliers, this translates to a total economic impact of $ 923 million or an incremental benefit of $ 460 million. For on-going operations, the present value total direct spending of the project is $ 142 million. Using the multipliers, this translates to a total economic impact of $ 283 million or an incremental benefit of $ 141 million.

From a total perspective, the present value total expenditure of the project is $ 606 million. Using the multipliers, this translates to a total economic impact of $ 1,206 million or an incremental benefit of $ 601 million.

Q. HOW REALISTIC ARE THESE VALUES OF INCREMENTAL BENEFIT?

A. In general, this translates into a multiplier that is close to 2 times. For manufacturing projects, I usually expect a higher multiplier. The level found here is not unexpected. However, if one wanted to take a more conservative view, one could examine the incremental value estimated using the lowest non-residential multiplier which is approximately 1.36. Using that multiplier, I find a minimum estimate of incremental economic benefit of \$ 219 million (0.36 times \$606 million).

Q. PLEASE SUMMARIZE THE FINDINGS FROM YOUR ANALYSIS?

A. From the application of the Input-Output multipliers to the projected spending on the smart meter system, I estimate that the incremental economic benefits from the project are \$ 601 million. I also find that under a very conservative approach, the value is \$219 million.

IX. <u>ELECTRONIC BULLETIN BOARD</u>

Q. PLEASE EXPLAIN WHY DE-OHIO IS PROPOSING AN ELECTRONIC BULLETIN BOARD IN CONNECTION WITH ITS APPLICATION FOR AN ELECTRIC SECURITY PLAN.

A. DE-Ohio seeks to provide competitive options and alternatives to its customers, such that customers can better manage their energy costs. Toward that end, DE-Ohio believes it is important to provide open access and information to pricing alternatives and energy cost information via an online electronic bulletin board (EBB). The EBB will be designed to provide competitive energy pricing alternatives to customers by publishing market based energy prices for customers. The EBB website will also be made available, at a marketer's discretion, for the posting of competitive marketer prices, should a marketer opt to make their competitive prices available to customers, as well. The online open access environment is intended to provide more information and choices to customers, to better help them manage their energy costs.

Q. PLEASE IDENTIFY THE VARIOUS CUSTOMER GROUPS THAT MAY PARTICIPATE IN THE ELECTRONIC BULLETIN BOARD PROCESS.

A. Customer groups will be established based on load profile analysis, where customers with similar monthly and hourly usage patterns will be grouped together. Alternatively, individual customers larger than 100KW, with interval hourly meters, may request in writing that their accounts be specified individually such that competitive marketer offers can be specifically made available for their inspection, and possible selection, thereby increasing the relevancy of the EBB to as many customers as possible, and insuring that competitive markets are nurtured and supported through this transition period.

Q. ARE THERE ANY LIMITATIONS RELATIVE TO THE ELECTRONIC BULLETIN BOARD?

A. Yes.

Q. PLEASE EXPLAIN THOSE LIMITATIONS.

A. A customer that switches to the EBB price must stay at the EBB price or take service from a competitive retail electric service provider.

Q. WHAT IS THE RATIONALE FOR THIS LIMITATION?

A. DE-Ohio faces significant risk in meeting its obligation to serve where large groups of customers migrate to and from provider of last resort (POLR) service. Generally, energy markets are volatile; energy prices can rise and fall quickly. Unchecked, the movement of customers back and forth from standard ESP service to market based pricing, and back again, can potentially cause the need for increased reserve margins and costs to cover the risks posed by significant customer migrations to and from POLR service. Alternatively, this single, simple restriction placed on the flow back and forth to and from ESP and competitive markets (i) minimizes the potential increased reserve margin costs in POLR type service, (ii) allows customers the choice to remain with the ESP service, or participate in open markets at any time, and (iii) only places one restriction on customers that they not return to ESP, once they opt to participate in competitive markets.

Q: WERE THE ATTACHMENTS TO YOUR TESTIMONY PREPARED BY YOU OR AT YOUR DIRECTION?

A: Yes.

X. CONCLUSION

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

A. Yes.

Duke Energy Ohio - Forecast
No Legislative Impacts

	Residential	Commercial	Industrial	Other Public Authority	Street Light	Company Use	Inter Department	Total Deliveries	Losses	Sendout	Summer Peak
2008	7,433,641	6,325,748	5,737,161	1,559,954	104,387	20,735	7,615	21,189,241	1,506,887	22,696,128	4,446
2009	7,539,132	6,407,887	5,731,627	1,565,881	104,403	20,946	7,692	21,377,568	1,520,270	22,897,838	4,489
2010	7,652,536	6,500,776	5,785,450	1,578,219	104,504	21,154	7,770	21,650,409	1,539,662	23,190,071	4,548
2011	7,813,496	6,614,964	5,890,396	1,605,561	104,679	21,366	7,849	22,058,311	1,568,632	23,626,943	4,637
2012	7,762,236	6,688,762	6,004,816	1,439,244	104,858	21,580	7,926	22,029,422	1,566,594	23,596,016	4,674
2013	7,663,616	6,750,160	6,094,089	1,252,141	105,022	21,795	8,002	21,894,825	1,557,078	23,451,903	4,687
2014	7,553,777	6,807,021	6,164,575	1,061,868	105,238	22,014	8,084	21,722,577	1,544,881	23,267,458	4,694
2015	7,585,379	6,903,260	6,223,799	1,027,672	105,465	22,233	8,166	21,875,974	1,555,844	23,431,818	4,737
2016	7,612,253	6,999,439	6,284,714	990,930	105,702	22,454	8,247	22,023,739	1,566,411	23,590,150	4,797
2017	7,626,388	7,095,710	6,346,085	953,150	105,906	22,679	8,331	22,158,249	1,576,051	23,734,300	4,817
2018	7,638,818	7,191,616	6,407,945	914,914	106,117	22,904	8,412	22,290,726	1,585,549	23,876,275	4,855
2019	7,648,083	7,286,519	6,469,481	876,118	106,361	23,135	8,499	22,418,196	1,594,691	24,012,887	4,892
2020	7,650,584	7,381,713	6,529,617	836,439	106,623	23,365	8,582	22,536,923	1,603,219	24,140,142	4,926
2021	7,685,781	7,482,769	6,591,584	830,400	106,928	23,599	8,669	22,729,730	1,617,017	24,346,747	4,994
2022	7,717,896	7,582,588	6,658,042	825,030	107,267	23,836	8,755	22,923,414	1,630,882	24,554,296	5,036
2023	7,747,255	7,681,058	6,724,776	820,087	107,641	24,074	8,842	23,113,733	1,644,512	24,758,245	5,053
2024	7,775,080	7,777,763	6,792,939	815,035	108,069	24,316	8,928	23,302,130	1,658,002	24,960,132	5,095
2025	7,801,661	7,871,378	6,861,149	810,401	108,519	24,558	9,019	23,486,685	1,671,214	25,157,899	5,135
2026	7,826,950	7,960,128	6,928,129	805,443	109,006	24,802	9,110	23,663,568	1,683,881	25,347,449	5,173
2027	7,851,938	8,045,091	6,997,063	800,576	109,535	25,053	9,199	23,838,455	1,696,399	25,534,854	5,236
2028	7,877,286	8,131,013	7,066,883	795,936	110,067	25,307	9,289	24,015,581	1,709,051	25,724,632	5,250

Duke Energy Ohio - Energy Efficiency Forecast
Impacts Required to Meet the Requirements of House Bill 221

	Energy Percent Reductions Required		Energy Calculated Reductions Required*		Energy Accumulated Reduction	Energy Calculated Reductions Net of Credit	
	Incremental	Cumulative	Incremental	Cumulative	Credit - 1998 thru 2008	Incremental	Cumulative
2009	0.30%	0.30%	68,127	68,127	115,642	-	-
2010	0.50%	0.80%	113,396	181,523		65,881	65,881
2011	0.70%	1.50%	159,371	340,894		159,371	225,252
2012	0.80%	2.30%	183,248	524,142		183,249	408,501
2013	0.90%	3.20%	208,271	732,413		208,271	616,772
2014	1.00%	4.20%	233,010	965,423		233,010	849,782
2015	1.00%	5.20%	233,321	1,198,744		233,322	1,083,104
2016	1.00%	6.20%	231,965	1,430,709		231,964	1,315,068
2017	1.00%	7.20%	230,587	1,661,296		230,588	1,545,656
2018	1.00%	8.20%	229,629	1,890,925		229,628	1,775,284
2019	2.00%	10.20%	458,515	2,349,440		458,515	2,233,799
2020	2.00%	12.20%	457,656	2,807,096		457,655	2,691,454
2021	2.00%	14.20%	455,137	3,262,233		455,138	3,146,592
2022	2.00%	16.20%	450,988	3,713,221		450,988	3,597,580
2023	2.00%	18.20%	445,527	4,158,748		445,527	4,043,107
2024	2.00%	20.20%	440,354	4,599,102		440,354	4,483,461
2025	2.00%	22.20%	435,533	5,034,635		435,533	4,918,994

* Uses three year moving average of Sendout

	Peak Percent Reductions Required		Peak Calculated Reductions Required*		Peak Accumulated Reduction	Peak Calculated Reductions Net of Credit	
	Incremental	Cumulative	Incremental	Cumulative	Credit - 1998 thru 2008	Incremental	Cumulative
2009	1.00%	1.00%	45	-	48	-	-
2010	0.75%	1.75%	78	30		30	30
2011	0.75%	2.50%	111	63		33	63
2012	0.75%	3.25%	145	97		34	97
2013	0.75%	4.00%	179	131		34	131
2014	0.75%	4.75%	214	166		35	166
2015	0.75%	5.50%	248	200		34	200
2016	0.75%	6.25%	282	234		34	234
2017	0.75%	7.00%	316	268		34	268
2018	0.75%	7.75%	350	302		34	302
2019	0.75%	8.50%	384	336		34	336
2020	0.75%	9.25%	418	370		34	370
2021	0.75%	10.00%	453	405		35	405
2022	0.75%	10.75%	487	439		34	439
2023	0.75%	11.50%	521	473		34	473
2024	0.75%	12.25%	556	508		35	508
2025	0.75%	13.00%	590	542		34	542

* Uses three year moving average of Peak

Bureau of Economic Analysis RIMS II Multipliers
Cincinnati Metropolitan Statistical Area

Exhibit RGS 3

Industry Group	Final-demand Output (dollars)
1. Crop and animal production	1.7424
2. Forestry, fishing, and related activities	1.6211
3. Oil and gas extraction	1.0000
4. Mining, except oil and gas	1.8457
5. Support activities for mining	2.0167
6. Utilities*	1.3618
7. Construction	2.1636
8. Wood product manufacturing	1.8244
9. Nonmetallic mineral product manufacturing	2.0004
10. Primary metal manufacturing	1.8650
11. Fabricated metal product manufacturing	2.0455
12. Machinery manufacturing	2.1372
13. Computer and electronic product manufacturing	2.1250
14. Electrical equipment and appliance manufacturing	1.9888
15. Motor vehicle, body, trailer, and parts manufacturing	2.3026
16. Other transportation equipment manufacturing	1.8558
17. Furniture and related product manufacturing	2.0978
18. Miscellaneous manufacturing	2.1575
19. Food, beverage, and tobacco product manufacturing	2.1870
20. Textile and textile product mills	1.9107
21. Apparel, leather, and allied product manufacturing	2.0319
22. Paper manufacturing	2.1961
23. Printing and related support activities	2.2681
24. Petroleum and coal products manufacturing	1.7621
25. Chemical manufacturing	1.9155
26. Plastics and rubber products manufacturing	2.1769
27. Wholesale trade	1.8930
28. Retail trade	1.9925
29. Air transportation	1.8299
30. Rail transportation	1.8676
31. Water transportation	2.0857
32. Truck transportation	2.1608
33. Transit and ground passenger transportation*	2.1503
34. Pipeline transportation	1.6567
35. Other transportation and support activities*	1.9219
36. Warehousing and storage	1.9605
37. Publishing including software	2.0462
38. Motion picture and sound recording industries	1.8378
39. Broadcasting and telecommunications	1.9421
40. Information and data processing services	2.0121
41. Federal Reserve banks, credit intermediation and related servic	1.7872
42. Securities, commodity contracts, investments	2.1890
43. Insurance carriers and related activities	2.1716
44. Funds, trusts, and other financial vehicles	2.2393
45. Real estate	1.4594
46. Rental and leasing services and lessors of intangible assets	2.1571
47. Professional, scientific, and technical services	2.0770

48. Management of companies and enterprises	2.0958
49. Administrative and support services	2.0726
50. Waste management and remediation services	2.0315
51. Educational services	2.1465
52. Ambulatory health care services	2.0891
53. Hospitals and nursing and residential care facilities	2.1764
54. Social assistance	2.1150
55. Performing arts, museums, and related activities	2.0897
56. Amusements, gambling, and recreation	1.9719
57. Accommodation	1.9339
58. Food services and drinking places	2.0710
59. Other services*	2.1112
60. Households	1.3257

Attachment RGS 4

Economic Impact of Smart Meter Project

Impact of Direct Investment

	Input-Output Multipliers Final-demand Output (dollars)	Components	Project Cost 20 Year Present Value	Total Economic Value	Incremental Value
Computer and electronic product manufacturing	2.1250	Hardware	$ 9,043,988	$ 19,218,475	$ 10,174,487
Electrical equipment and appliance manufacturin	1.9888	Equipment (1)	$ 471,500,339	$ 937,719,875	$ 466,219,535
Information and data processing services	2.0121	Software and IT labor	$ 26,333,978	$ 52,986,597	$ 26,652,619
Total			$ 506,878,305	$ 1,009,924,946	$ 503,046,641

Impact of Operational Direct Spending

	Input-Output Multipliers Final-demand Output (dollars)	Components	Project Cost 20 Year Present Value	Total Economic Value	Incremental Value
Utilities	1.3618	Power usage	$ 6,802,523	$ 9,263,676	$ 2,461,153
Computer and electronic product manufacturing	2.1250	Hardware and support	$ 13,408,335	$ 28,492,711	$ 15,084,377
Electrical equipment and appliance manufacturin	1.9888	Service contracts and maintenance	$ 33,359,642	$ 66,345,656	$ 32,986,014
Information and data processing services	2.0121	Software maintenance	$ 93,219,645	$ 187,567,248	$ 94,347,603
			$ 146,790,145	$ 291,669,292	$ 144,879,146

Total Project Costs, Economic Value and Incremental Value

	Project Cost 20 Year Present Value	Total Economic Value	Incremental Value
Capital	$ 506,878,305	$ 1,009,924,946	$ 503,046,641
Operation and Maintenance	$ 146,790,145	$ 291,669,292	$ 144,879,146
Total	$ 653,668,450	$ 1,301,594,238	$ 647,925,788

(1) Meters, communication equipment, distribution automation equipment, and installation