Advanced Metering Infrastructure (AMI) Evaluation

Final Report

Completed for Commonwealth Edison Company (ComEd)

July 2011

AMI Evaluation Project Acknowledgements

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Black & Veatch acknowledges the participation and active support provided by the ComEd AMI project team as well as the Regulatory, Finance, Business, and IT team members in the execution of this evaluation.

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July 8, 2011

Mr. Richard D. O'Toole
Director, Customer Strategy/Smart Metering
Commonwealth Edison Company (ComEd), an Exelon Company

Dear Richard:

We are pleased to present to ComEd our "Advanced Metering Infrastructure (AMI) Program Evaluation" report describing the operational AMI cost-benefit framework and business case evaluation. The purpose of the evaluation and report is to assist ComEd in assessing the reasonableness and justification of an AMI deployment within ComEd's service territory. Given the detailed business case analyses performed by the ComEd / Black & Veatch team, and leveraging the data and lessons learned from ComEd's AMI Pilot, the results of this evaluation provide important and useful insights into the potential costs and benefits to ComEd and its customers through the described AMI/Smart Meter implementation.

Following the stakeholder workshop on May 19, 2011, we have updated the report to more specifically address some of the comments and topics discussed; however, the fundamental inputs to the results of the evaluation remain unchanged. We are confident that this evaluation, while limited in scope to AMI impacts, will provide your organization valuable information it may use to further promote and support the benefits of the AMI program to the Illinois Commerce Commission (ICC) and other Smart Grid stakeholders.

We welcome opportunities to be of further assistance to ComEd in this important matter.

Sincerely,

Andrew L. Trump

Kolten K. Sarver

BLACK & VEATCH CORPORATION

Qualifications Associated with the Black & Veatch AMI Cost-Benefit Evaluation:

- Black & Veatch Corporation (Black & Veatch) is providing this report to Commonwealth Edison Company (ComEd) to provide an "operational" cost-benefit business case evaluation of a potential AMI implementation throughout ComEd's service territory. The term "operational" indicates that the scope is focused on AMI specifically and a ComEd-delineated set of potential costs and benefits. In performing this evaluation, Black & Veatch used methodologies that follow generally accepted professional industry standards in estimating these projected costs and benefits.
- In connection with performing this evaluation and preparing this report, Black & Veatch examined and used documents supplied by ComEd. Black & Veatch has assumed that the information set forth in these documents is accurate and reliable for purposes of the evaluation.
- Black & Veatch stresses that the estimated net customer impact and cash flows are offered as useful estimates, but are not offered as final and definitive work products for ComEd's regulatory filing requirements for cost recovery. We have provided comments about additional work effort likely to be required to prepare the financial analyses for a regulatory filing.
- Black & Veatch is submitting this work product report to ComEd. Black & Veatch will not separately release this report, except as required by law. Black & Veatch understands that the evaluation report (or portions thereof) may be submitted to the Illinois Commerce Commission (ICC) by ComEd in satisfying its obligations and/or requirements to the ICC.
- Black & Veatch has no control over many variables that may influence the actual implementation and support costs, avoided costs, and other benefit categories of a proposed future deployment of AMI (e.g., actual labor costs, outcomes of vendor solicitations, price inflation, etc.) ComEd's actual implementation experience and results may vary from cost and avoided cost estimates provided in this report.

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1 Executive Summary

This report describes an evaluation performed by Black & Veatch of an Advanced Metering Infrastructure (AMI) implementation throughout the Commonwealth Edison (ComEd) service territory. In conducting this evaluation, Black & Veatch worked closely with the ComEd AMI project team and business managers over a five-month period (January 2011 – May 2011) to refine the scope of the AMI investment, gather AMI Pilot results, develop operational data and projections, identify and resolve key business case formation questions, and construct an independent view of the AMI business case.

The overall results of the evaluation are positive. On the cost side, ComEd will incur new costs for AMI meters, the wireless or Radio Frequency (RF) communications network, IT systems, implementation services, and on-going operational expenses. Over the 20-year evaluation period, assuming a five-year meter deployment scenario, ComEd would expect to invest $996 million in new capital and incur $665 million of operational costs to run the system.

Cumulative benefits over the 20-year evaluation period, however, significantly exceed cumulative costs by a factor of almost three. Benefits result from improved operational efficiencies ($1,625 million), reduced power purchase costs ($707 million), reduction in bad debt expenses ($791 million), new energy revenues ($1,051 million), and new delivery service revenues ($564 million). A large majority of these benefits are driven by reductions in theft and tamper conditions[1] and reductions in consumption on inactive accounts.[2]

Taking account of all costs and benefits, and assuming adjustments to customer rates, the Net Present Value (NPV) is $1,296 million over the 20-year evaluation term. This is the value of the AMI program *to the ComEd customer*.[3] This result is independent of ComEd's demand response programs or plans.

Table 1.1 summarizes the cost and benefit results of both a five-year and a ten-year AMI meter deployment scenario.

[1] The evaluation includes a benefit related to Unaccounted for Energy (UFE). UFE includes losses due to theft and meter tamper conditions. The evaluation estimates that theft and tamper conditions will be reduced with AMI, and so UFE will decline. Note that UFE also includes other forms of distribution system losses that are unaffected by AMI. In this report, however, UFE is used narrowly to refer to the reduction in energy lost through theft, meter tamper, and other customer behaviors impacted with AMI business process changes.

[2] The evaluation includes a benefit related to Consumption on Inactive accounts (CIM). Under current operations (prior to AMI), there are instances of metered consumption (at a premise) without an active customer account. These occurrences are usually the result of limited field work capacity to physically disconnect electricity at a premise after finalizing an account.

[3] Consistent with ISSGC recommendations, a discount rate is used for the NPV calculation which reflects a customer and not a corporate perspective.

Table 1.1 Financial Highlights and Summary (5-Year and 10-Year Deployment, $ in millions)

Item	Base Case (5-Year Deployment)	Base Case (10-Year Deployment)
A. Costs (Cumulative 20 years)		
O&M Expense for AMI System	$665	$653
New Capital Investment for AMI System	$996	$1,031
Sub-Total	***$1,661***	***$1,684***
B. Operational Benefits & Delivery Service Revenues (Cumulative 20 years)		
Operational Efficiencies and Cost Reductions	$1,625	$1,539
Avoidance of Capital Expenditures	$3	$3
Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$564	$531
Sub-Total	***$2,192***	***$2,073***
C. Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cum. 20 yrs)		
Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM[4]	$708	$667
Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$1,051	$991
Reduction in Bad Debt Expenses	$791	$745
Sub-Total	***$2,550***	***$2,403***
D. Total (Cumulative 20 years)		
Benefits Less Costs	**$3,081**	**$2,795**
E. Net Customer Impact		
Net Present Value (NPV) [5]	***$1,296***	***$1,152***
Discounted Payback Period (Customer Perspective)	***8 years***	***9 years***

All $ values in Millions. NPV calculated based on discount rate = 4.27% (20-yr Treasury Rate)

These evaluation results update the results ComEd delivered to the Illinois Commerce Commission (ICC) during 2008 and reviewed in 2009 workshops.[6] The payback period has shortened by eight years (from sixteen to eight years) and the net customer impact (on NPV basis) has improved from $28 million to $1,296 million due to the large increase in estimated avoided purchased power, reduction of bad debt, and increase

[4] Energy purchased power costs include power costs, transmission rights, and other related energy costs.

[5] The Net Present Value (NPV) and Discounted Payback Period presented in this report represent the discounted difference between the costs to consumers (consumer rates) and the costs to consumers under the existing system, without AMI. For convenience, the net of all these costs and benefits is defined as the *net customer impact*. Calculation of this net customer impact is shown in Appendix D.5. Furthermore, in Table 1.1, *Collection of Delivery Service Revenues Due to Reduction in UFE and CIM* (under item B), and *Collection of Energy Revenues Due to Reduction in UFE and CIM* (under item C) isolate *revenue* impacts. In reality, these revenue impacts mean that the number of billing units (kWh, bills, and kWs) used to design rates will *increase*. Through the rate making process, this will *reduce* customer rates overall. The bottom line is that each of the benefits described in Table 1.1 will flow to customers and is captured in the NPV result, but some of the benefits require a rate making process to pass-through to customers.

[6] Source documentation for the Winter 2009 report includes the ComEd January 29, 2009 presentation "AMI Pilot Discussion, ComEd Operations.".

in energy and delivery service revenues.[7] Capital costs are 10% higher in today's evaluation and yearly operations costs are 50% higher ($30 million today versus an earlier estimate of $20 million). The benefits included in this evaluation, and specifically those estimated for avoided energy and bad debt expenses, as well as energy and delivery revenues, represent a significant increase compared to those identified in the prior results.

Energy use reductions are assumed in the UFE benefits summarized in Table 1.1. Additional energy reductions, above and beyond those associated with UFE, are also estimated as a result of voluntary customer reductions attributed to available web-based presentment of a customer's energy usage information.[8] Collectively, energy reductions due to UFE *and* voluntary customer reductions result in an estimated conservation equivalent of 380,000 MWh/year. Additionally, ComEd's capacity requirements are estimated to be reduced by 43 Megawatt (MW). Black & Veatch does not view the energy and capacity reductions as large enough to influence market prices. The reductions will reduce emissions equivalent to the emissions generated by the operation of one modest sized power plant during 10% of its operating hours.

Finally, the AMI infrastructure contemplated is foundational to other programs, such as demand response initiatives, net-metering demands of plug in electric vehicles, distribution system asset monitoring and control, load control opportunities, and numerous other possibilities. This evaluation does not describe or speculate on the nature, timing, scope, or impact of these additional potential programs.

[7] Strict side-by-side comparisons are difficult due to the fact that different evaluation terms and discount rates were used, in addition to underlying differences on the classification of benefits.

[8] www.comed.com/smarttools

2 Evaluation Introduction and Overview

This report describes an evaluation performed by Black & Veatch to validate the Commonwealth Edison (ComEd) "operational" business case to determine whether a future full scale AMI deployment within ComEd's service territory is reasonable and justifiable from a cost-benefit perspective. "Operational" is used because the focus of the business case is on a specific set of benefits tied to operational improvements as distinct from demand side measures. To conduct this assessment, Black & Veatch worked closely with the ComEd AMI project team and the ComEd Customer Operations, Distribution Operations, Regulatory, and Finance managers over a four-month period (January 2011 – April 2011) to refine the scope of the potential AMI system investment, gather the pertinent AMI Pilot and operational data and projections, identify and resolve key business case formation questions, and construct an independent view of the business case and its results. The findings presented here update and modify the results ComEd offered to the ICC and its other stakeholders during the winter period of 2009.[9]

In performing this evaluation, Black & Veatch has paid particular attention to the sources of information, and has noted throughout this report when ComEd has offered information and judgment conditioned by its experience in designing, planning, and implementing the 131,000-meter AMI pilot system ("the Pilot"). It is Black & Veatch's opinion that the "lessons learned" from this Pilot are integral to this business case as they enable and support improved cost and benefit assumptions. Second, they provide guidance on the timing of cost occurrence and benefit realization. Third, they provide guidance for scoping full-scale implementation work efforts. Last, the lessons from the Pilot help inform the organization about uncertainties and risks that ComEd faces in pursuing future AMI investments.

Another key aspect of this evaluation is Black & Veatch's role in validating elements of the business case. Because "validation" can be interpreted very broadly, the scope of this validation activity must be defined and narrowed to have useful meaning. In this evaluation, consistent with the scope of work specified by ComEd for this engagement, Black & Veatch has reviewed ComEd's prior business case analysis, led the ComEd team in the identification and update of detailed cost and benefit assumptions, offered guidance about how to best estimate costs and benefits, and deployed a business case model and analytical methodology to ensure that costs and benefits are properly specified in a dynamic spreadsheet tool. Black & Veatch also offers observations in this report about opportunities to improve the business case. A sample of benchmarking information is also provided to help orient the reader to the nature and scope of the results compared to the experience of four other utilities. Collectively, these activities form the basis of Black & Veatch's validation efforts. Items not included in the validation work are also described in the report.[10]

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[9] Source documentation for the Winter 2009 report includes the ComEd January 29, 2009 presentation "AMI Pilot Discussion, ComEd Operations.".

[10] Black & Veatch has not reviewed information about ComEd's proposed smart metering system's technical specifications and characteristics and so it is not in a position to validate whether the system's technical specifications will meet a level of performance consistent with the levels of costs and benefits described in this report. Black & Veatch has also not reviewed certain policy issues identified by the ISSGC stakeholder report. However, ComEd managers responsible for the AMI Pilot indicate that the Pilot system performance is consistent with the detailed technical Request for Proposal (RFP) specification ComEd issued as part of its AMI system vendor selection process.

In performing this evaluation, Black & Veatch paid careful attention to the recommendations of the Illinois Statewide Smart Grid Collaborative (ISSGC) Collaborative Report.[11] ComEd's business case focuses on smart metering and specific operational improvements and opportunities directly tied to smart metering. Accordingly, only portions of the ISSGC report recommendations are germane to the effort described and summarized here. Specifically, and in deference to the ISSGC report, Black & Veatch aligned the work effort to the ISSGC recommendations regarding seven smart grid "applications." Given the scope of ComEd benefits, the scope is further aligned to the ISSGC "AMI Applications" category and several (but not all) of the AMI Applications within this category.

Additionally, the ISSGC offers recommendations about utility filing requirements. These include proposed requirements for compliance with technical characteristics and specifications, as well as a recommended cost and benefit framework for evaluating business case impacts. The evaluation largely excludes a review of the former item as this is outside the Black & Veatch work scope. The ComEd Stakeholder Workshop process developed an extensive base of information regarding technical performance and business case linkages; it was not deemed necessary to cover that ground in this evaluation.[12]

The evaluation, however, does meet many of the information requirements set out in the ISSGC cost and benefit framework recommendations. While important work remains for ComEd to further its business and technical planning, Black & Veatch believes the evaluation provides an important contribution for ComEd's ICC stakeholder process by providing important insights about the nature and scope of potential costs and benefits.[13]

Black & Veatch is confident that the information presented in this report is substantive, thorough, and presented within the context of a robust analytical process, both in terms of the data collection and the modeling specification, and will greatly assist ComEd and all stakeholders in future activities associated with regulatory review and approvals, should those steps ensue. For those gap areas that exist in relation to the ISSGC report recommendations, it is Black & Veatch's opinion that ComEd has developed the base of knowledge through its work with stakeholders as part of the AMI Pilot Workshop process, and through its practical hands-on implementation effort as part of the 131,000 meter Pilot, to bring forward the necessary additional information that would satisfy those requirements.

2.1 The Context of the Evaluation

This evaluation exists within a context of ComEd's objectives in pursuing its AMI initiative. These objectives have been set out by ComEd in various filings, workshop presentations, and other company

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[11] The report was submitted to the Illinois Commerce Commission (ICC) September 30, 2010. This report advances a framework for considering various smart grid investments and programs. The Report can be found as a link the ISSGC's web site: http://www.ilgridplan.org.

[12] See the ComEd AMI Future website for information pertaining to the ComEd AMI Pilot Workshops. http://comedamifuture.com.

[13] Black & Veatch has provided estimated financial results, including estimated revenue requirements. Further analysis and/or evaluation may be required in specific areas such as revenue requirements depending on the ComEd business or regulatory requirement.

communications, and will not be elaborated upon in this report. In reference to the Pilot, company representative Ross Hemphill testified to the ICC:

> [The AMI Pilot] is a critical step in ComEd providing its customers with significant additional benefits, including improved system performance, improved customer service, improved reliability, better information about customers energy use, and expanded opportunities for energy efficiency, effective demand response, and better-controlled electric costs. Ultimately, this will lead to a variety of economic and environmental benefits to northern Illinois and the nation as a whole.[14]
>
> Well-designed AMI technologies are recognized by policymakers, including the Commission, as contributing to improved system performance, customer empowerment, environmental improvement, and reduced and better managed customer energy costs. These policy goals are expressly reflected in a variety of statutes, declarations, orders, and policy statements as well as being evident in the nation's sharp movement toward the investigation and deployment of Smart Grid technologies.[15]

An information record exists that sets out ComEd's rationale for pursuing the AMI Pilot and potential full-scale deployment. The record consists of information provided to the public through its 2007 rate case, the findings of the Commission to approve the Pilot, and the important body of information created through the ISSGC stakeholder process.[16] Readers are encouraged to review the ComEd AMI Future website for additional information regarding overall program objectives.

Broadly, the AMI objectives relate to achieving long-term operational cost and performance efficiencies, reducing business inefficiencies related to bad debt and unmetered electricity use, reducing injuries and accidents, improving customer satisfaction, and creating a foundation through which the AMI system can be leveraged over time for advanced rate designs and distribution operations asset optimization. Black & Veatch finds a substantial degree of congruence between the estimated business case benefits and ComEd's and stakeholder's stated objectives.[17]

2.2 Evaluation Scope and Approach

The Black & Veatch evaluation includes (a) data discovery, (b) working sessions, (c) data evaluation and analysis, (d) financial modeling, (e) review meetings with ComEd managers and Customer Operations senior leadership, and (f) documentation and reporting. The evaluation includes work to validate the reasonableness of the ComEd business case, benchmark inputs and outputs when possible, and describe the lessons that have emerged from the ComEd Pilot. In conducting this work, Black & Veatch has attempted to follow the ISSGC recommendations to the degree reasonable given the limitations of the ComEd scope of work.

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[14] Direct Testimony of Ross C. Hemphill, PH.D., Commonwealth Edison Company, before the ICC, Docket No. 09-0263, Exhibit 1.0, page 9.

[15] Ibid, page 9-10.

[16] See ComEd AMI Future web site, http://comedamifuture.com,.

[17] This evaluation is related to core operational costs and benefits. It does not include demand response programs or advanced distribution operations-related opportunities, or programs impacting distribution system reliability.

Relative to the ISSGC Smart Grid areas, this evaluation is narrow in terms of the project under evaluation. The ISSGC report covers Smart Grid, identifying the following seven Smart Grid categories:

1. AMI Applications
2. Customer-oriented Applications
3. Demand Response Applications
4. Distribution Automation Applications
5. Asset/System Optimization Applications
6. Distributed Resource Applications
7. Transmission Applications

Only the first item—AMI Applications—is subject to this evaluation. Moreover, the ISSGC report identifies the following five separate "functional options" within the AMI Applications category[18]:

1. Core AMI Functionality
2. Remote Disconnect/Reconnect
3. Outage Management Support
4. Power Quality/ Voltage Monitoring
5. Customer Prepayment Utilizing AMI

Four of the five applications are subject to the evaluation in varying degrees. The ISSGC provides a framework for evaluating costs and benefits organized by application. This framework identifies potential application beneficiaries (utilities, third-party suppliers, market, etc.) as primary or secondary.[19] The Black & Veatch evaluation includes costs and benefits for AMI Applications in the following manner, consistent with this ISSGC Report framework (Table 2.1).

[18] ISSGC Report, Pages 57.

[19] See the ISSGC Report, pages 57 – 73 for a description of the AMI Applications area.

Table 2.1 ISSGC Applications and Evaluation Scope

ISSGC Identified Application Area	Costs	Benefits	Negative Impacts
Core AMI Functionality	Included in Black & Veatch evaluation	Included in Black & Veatch evaluation.	Partially included. The CAP, privacy, and hazards elements are out of scope of the evaluation.[20]
Remote Connect / Disconnect	Included in Black & Veatch evaluation	Included in Black & Veatch evaluation.	Black & Veatch defers to ComEd to provide its assessment of consumer and public health and safety concerns, as identified in the ISSGC report.
Outage Management Support	Included in Black & Veatch evaluation	Partial. No analysis of changes to system reliability or improved public safety because there is insufficient information available given the nature of the OMS benefits measured and learned about in the pilot.	N/A. (The ISSGC report does not identify any negative impacts.)
Power Quality / Voltage Monitoring	Partially included. Meter pricing assumes power quality and voltage measurement and signaling capabilities. Other system costs (such as how to integrate this data into utility applications) not included.	Excluded from the evaluation per ComEd scope direction.	N/A. (The ISSGC report does not identify any negative impacts.)
Customer Prepayment Utilizing AMI	Out of Scope of evaluation. ComEd does not have plans for prepayment applications at this time.	Out of Scope of evaluation: ComEd does not have plans for prepayment applications at this time.	Out of Scope of evaluation: ComEd does not have plans for prepayment applications at this time.

Note: Refer to Appendix I (ISSGC Defined AMI Costs and Potential Benefits) for additional detail about how this evaluation addresses the defined ISSGC costs and potential benefits.

Table 2.2 below provides further details regarding those AMI capabilities, costs, and/or benefits that are either included within or excluded from the evaluation, along with supporting rationale.

[20] Items excluded in Table 2.1 were determined by ComEd to be outside of the Black & Veatch scope of work

Table 2.2 Evaluation Scope: Further Details on AMI Functionality

AMI Area of Functionality	Included	Excluded	Comments
Core AMI Functionality	4M highly capable smart meters and the requisite communications network compliant with known smart grid standards and requirements; cost recovery of the retired meter asset	End-of-Life Smart Meter Replacement costs; Severance	"As-Is" and "To-Be" costs for replacement meters are assumed similar in value, so treated as no impact to the NPV. ComEd separately analyzing severance and recovery treatment of existing retired meters
Remote Connect / Disconnect	Functionality to improve collections and reduce unbilled energy	Costs to support a door knock or other requirements of an on-site presence prior to disconnection for non-payment	IL Part 280 discussions remain open
Outage Management Support	Functionality to support basic restoration confirmation	Future integration to support advanced outage detection, restoration confirmation, and customer notifications	Model reflects the costs and benefits associated with what was tested in the pilot
Other Smart Grid capabilities	Meter pricing assumes advanced functions to support anticipated future needs (e.g., voltage, net metering)	Voltage regulation; power factor monitoring; electric vehicle charging	Assumes Smart Grid capabilities will require individual cost/benefit analyses
Other Customer or Demand Response programs	Daily usage information available over the internet	Customer systems enhancements/replacement to support dynamic pricing; support for in-home displays	Similar to the Other Smart Grid capabilities, these applications are not considered core to the operational business case

2.3 Benefit Information

To gather benefit data, it was necessary to conduct an orderly process to uncover and/or confirm the likely business process impacts of the AMI applications in each of the following ComEd departments: Meter Reading, Field and Meter Services (F&MS), AMI Operations, Billing, Call Center, Revenue Management, Revenue Protection, and Distribution System Operations. Many of the business impacts were already identified by ComEd as part of previous AMI planning work and Pilot implementation,[21] but these impacts needed to be confirmed, updated with lessons from the Pilot, and under certain circumstances expanded or contracted based on insights offered by the workshop participants. Importantly, the financial impacts of

[21] See Direct Panel Testimony of Richard O'Toole, Director, AMI Pilot Project, and David Doherty, Manager, Advanced Metering Infrastructure Pilot Project, Commonwealth Edison, Docket No. 09-0263, ComEd Exhibit 3.0.

each benefit area needed to be explored in terms of an extrapolation over an extended timeframe as part of the "As Is" scenario (no AMI) and "To Be" (with AMI) scenario.[22]

For each department, it was necessary to collect information about existing and likely future business process or practice changes, anticipated activity levels, personnel requirements, and other resource requirements. A key part of this work developed a common set of assumptions about how reductions and impacts in one department area affect other departments. For example, AMI automation modifies work activities and volumes in Field Meter Services (e.g., connects and disconnects), and also introduces new responsibilities to the Call Center during deployment. New business practices in areas of Revenue Protection drive reductions and increases in the quantities and types of field trips handled by Field Meter Services as work flows change. These inter-departmental impact assumptions are important substrata of the business case work.

For benefits related to operational efficiencies and cost reductions (Meter Reading, Field Meter Services, Call Center, and Billing), the analysis involved forming three sets of data, as illustrated in Figure 2.1. First, activities and activity levels needed to be specified for the current business ("As Is") and the future business with AMI ("To Be"). Second, Full Time Equivalent (FTE) personnel resources and non-personnel resource requirements had to be specified for each scenario. Third, combined with detailed deployment modeling, budget impacts were extrapolated over the 20-year evaluation timeframe. With this data specified for both the "As Is" and the "To Be" scenarios, a comparison was made of avoided costs within each year period.

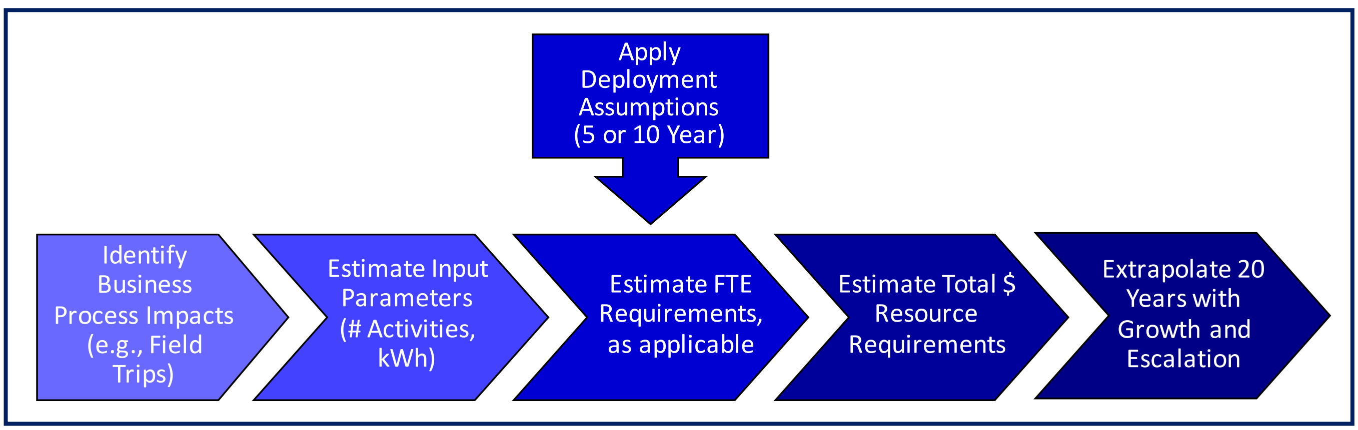

Figure 2.1 Data Collection Steps in Estimating "As Is" and "To Be" Scenarios

[22] Black & Veatch's method is to define the "As Is" and "To Be" as separate scenarios. The *comparison* of the two scenarios becomes a "case," and by its nature yields the incremental effects of AMI. There are two "cases" evaluated: the five-year and ten-year deployment cases. Sensitivities are performed on the cases.

Data discovery meetings with ComEd's AMI Operations team members, including IT managers provided an understanding of the IT system, integration, and process change requirements necessitated by the intended AMI system solution implementation. Additionally, high-level system architectures and deployment plans were reviewed; and AMI planning, design, implementation, and operations and maintenance cost data associated with these plans were developed.

For each estimated benefit, the detailed findings are documented in Appendix F "Detailed Benefit Descriptions." These information templates describe the benefits that derive from the operational business case. Each ComEd manager was responsible for working with the evaluation team to complete these templates and ensure that they represent likely and reasonable AMI system-related business impacts.

2.4 Cost Information

Development of cost information to implement AMI came largely from the AMI Pilot operations team with input from the Exelon Business Services organization. Information related to the AMI Pilot implementation was reviewed and applied to estimate a cost infrastructure for the full service territory implementation. Certain proprietary vendor pricing assumptions were validated through contact with vendors. Meter functionality requirements were reviewed and meter-pricing estimates were confirmed by ComEd. Black & Veatch used its knowledge gained through other utility sourcing assignments in reviewing the cost data and offering judgment about the general reasonableness of the data.

The scope of work for field installation activities was developed and cost estimates to perform this work were provided to Black & Veatch by ComEd, assuming the use of internal resources. IT managers provided input to the IT infrastructure anticipated for installation to support the AMI system (AMI, Meter Data Management system, middleware systems, web presentment, configuration, and integration activities).

The cost information that was assembled included confirmation of the business structure that ComEd anticipates deploying for the AMI "head end" support and operations. The evaluation assumes that the hosting and required support of the AMI technology and system will be outsourced to a vendor through a service performance contract. This includes support of both the AMI hardware and software applications. The day-to-day business operations of the AMI solution will be performed by ComEd's AMI Operations team. This team will be responsible for monitoring, managing, and reporting on relevant AMI business operations such as: AMI communication failures, meter read upload failures, and meter deployment / installation status.[23]

The evaluation includes and accounts for an assumed accelerated regulatory recovery of the costs associated with current meters (non-AMI) that will be removed from service (during the deployment period) before being fully depreciated. For the purpose of this evaluation, Black & Veatch has relied wholly upon ComEd's Finance team to provide plant accounting estimates of the value of its currently deployed meter fleet as well as the annual costs of the accelerated recovery. Black & Veatch has neither performed any

[23] The operators of the AMI "head end" would interface with ComEd's operations managers and field technicians to determine field maintenance requirements. Presumably, the AMI data center operation would be structured around a detailed contract and Service Level Agreement (SLA) that would lay out explicit roles and responsibilities and performance requirements. Black & Veatch did not review materials in this regard.

separate analysis in this area nor validated the calculations and/or assumptions ComEd used in developing these cost recovery values.

2.5 Items Out-of-scope of the Evaluation

In addition to the ISSGC report recommendations noted in Table 2.1 and further details described in Table 2.2, the Black & Veatch evaluation is limited in its scope in the following areas:

Black & Veatch has not provided in this evaluation a detailed review of system functionality, technical requirements, or technical specifications. For example, as it relates to Core Functionality of the AMI system category described by the ISSGC report (Task 4), Black & Veatch has relied on ComEd's representations that the RF Communications system deployed for the Pilot meets the necessary technical and performance requirements to support the AMI-driven operational benefits described in this report.[24] The Stakeholder Workshop materials and ComEd's AMI Pilot testimony to the ICC help support ComEd's review of technical performance considerations.[25] Rather, Black & Veatch's evaluation has centered on the general alignment of ComEd's business requirements and the estimated business process impacts associated with these requirements; focusing on the determination of costs and benefits, not whether the specific system and vendor under consideration is capable of meeting the requirements.[26] It is important to note that ComEd has 1.5 years of operational experience in operating the Pilot system and ComEd has indicated that it has validated performance levels in many critical areas.[27] Given its documented successes to date in operating the extensive 131,000 meter pilot, an arguably more critical consideration for ComEd in achieving the full-scale AMI business objectives is rigorous business planning. This includes detailed design of requirements, processes, systems, integrations, work scopes, contracts, and service level agreements to guide the work and to ensure that it can meet the demands of scaling the system from today's level of meter deployment—representing 3% of ComEd's total meter population—to over 4 million. This planning is not part of this evaluation and is identified as one uncertainty (and therefore risk) of the business case. See Section 6 (Smart Meter Requirements and Specifications) for a description of ComEd's functionality and performance assumptions.[28]

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[24] This is just one example. The smart metering solution is composed of separate systems that are integrated and act as a whole. Black & Veatch has not been part of the work to specify the technical and performance requirements for each of these systems, or identified business and information system design and re-design requirements for these systems. Some information system and process design issues and dependencies are identified in Appendix F Detailed Benefit Descriptions. More importantly, the reader is encouraged to review the large body of information available through the ComEd AMI Future website (workshop materials link).

[25] See Direct Panel Testimony of Richard O'Toole, Director, AMI Pilot Project, and David Doherty, Manager, Advanced Metering Infrastructure Pilot Project, Commonwealth Edison, Docket No. 09-0263, ComEd Exhibit 3.0

[26] Black & Veatch has identified some of the business and information system design and re-design requirements for these systems in Appendix F, Detailed Benefit Descriptions

[27] See the ComEd Quarterly Reports to the ICC. Also see additional implementation information provided by ComEd available on the ComEd AMI Future website, at http://comedamifuture.com/.

[28] See the ComEd AMI Future website for additional information regarding technical performance. See Appendices to AMI Workshop Report 03-09-2009.pdf. Within this document is a section for ComEd's Pilot RFP and technical specifications for vendor compliance.

Similarly, Black & Veatch has not performed any assessment of emerging cyber security and interoperability standards and requirements. The Smart Grid community is constantly evolving the largely voluntary industry standards that meet critical utility and utility customer security and interoperability requirements. Currently, the Federal Energy Regulatory Commission (FERC) is evaluating the sufficiency of various frameworks for voluntary standards in meeting utility requirements. FERC has statutory requirements to do so. It is beyond Black & Veatch's scope in this evaluation to comment on the sufficiency of the ComEd Pilot end-to-end AMI communications system to meet these evolving requirements. Black & Veatch identifies this item in the report as one of the recommended areas of further investigation by ComEd.

The evaluation provides a business case; it is not a detailed business plan. The business case evaluates a 20-year investment and operations timeframe. As such, it makes certain simplifying assumptions. Often it is convenient (and appropriate), for example, to scale costs and benefits in proportion to and at the same rate as the deployment of meters.[29] Detailed business planning for budget and change management purposes will most likely refine these assumptions. Consistent with the above, the evaluation has not attempted to analyze specific deployment options except for the general five-year and ten-year deployment scenarios included in this evaluation. The evaluation assumes no specific sequencing and optimization of the deployment schedule. This is an example of where the business case is conservative. It may be possible for ComEd to implement a deployment plan in a way that captures high cost-to-service and high benefit areas early in the deployment cycle.

In some instances, validating the quality of data used in the evaluation is based on Black & Veatch professional judgment and experience in sourcing or procurement activities. Examples include the ComEd meter price assumptions and the cost assumptions for meter field installation work. In both instances, the ComEd assumptions are reasonable and align with Black & Veatch experience gained through numerous solicitation projects for other utilities. This is done without any specific reference to confidential work performed for other utilities. Rather it is confirmation that the ComEd pricing falls into typical norms found in the market. Black & Veatch has not been asked to validate the ComEd cost input assumptions through separate means, except to rely on ComEd data. There are also many reasons why these values may be low or high depending on market conditions largely outside of ComEd's control (until enforceable contracts for all provisioning requirements are put in place).

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[29] Certain benefits are modeled with 12-month lags. The benefit does not accrue at the time of the smart meter deployment; it lags by 12 months. In some instances this is a conservative assumption. Business readiness planning may improve the results accordingly.

3 ComEd AMI Project Information Resources

Readers are encouraged to review an extensive body of information that has been developed as part of ComEd's efforts to plan and implement the AMI Pilot during the past several years. This evaluation is largely a financial evaluation of business case impacts and is not intended to cover topics addressed in other forums.

One important source of information is the body of work associated with a series of workshops with AMI process stakeholders. The stated goal of the workshops: to "develop strategies, goals, timelines, and evaluation and technology selection criteria for the AMI pilot program."[30] These workshops were organized and led by the ICC with the assistance of outside consultants and supported by ComEd's Pilot team. SAIC has established a website documenting the information provided as part of the workshops series, which can be found at: http://comedamifuture.com.

Readers are encouraged to review several quarterly reports prepared by ComEd and filed with the ICC detailing the progress of the AMI Pilot. These reports provide insight into the scope of ComEd's activities, and reveal the degree of implementation work being conducted and the challenges faced and lessons learned. The reports can also be found at http://comedamifuture.com/. They cover details on ComEd's implementation experience. Examples of topics covered include the following:

- Meter installation work experience; "unable to complete" rate; customer appointment process and improved proactive customer communication program
- Customer satisfaction with installation experience
- Filing of Customer Applications Program (CAP) tariff (Rider AMP-CA)
- Release of an AMI Smart Tools website
- Challenges with interval billing
- Experience and lessons from a major storm event
- Remediation of RF communication challenges
- Reactions and workarounds due to unforeseen challenges

Additionally, ComEd has filed testimony with the ICC in its 2007 rate case (ICC Docket No. 07-0566) and in its 2009 AMI Pilot filing (ICC Docket No. 09-0263). Various parts of the ComEd testimony provide useful background information on the nature, scope, technical merits, and vendor requirements of the Pilot.

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[30] http://comedamifuture.com.

4 ISSGC Report Recommendations[31]

This report describes an evaluation performed by Black & Veatch to validate the Commonwealth Edison (ComEd) "operational" business case. The validation work and resulting analysis is preliminary and does not intend to represent ComEd's prospective regulatory filing to the ICC. Any speculation or description of the nature, scope, and timing of any such regulatory filing is beyond Black & Veatch's scope of work.

At the same time, the Black & Veatch evaluation is intended to provide a foundational element of ComEd's business case specifically as it relates to the AMI investment, and support ComEd's "next steps" with its stakeholders. As part of this effort, and as a foundation for future work, the Black & Veatch evaluation has endeavored to meet in principle, if not in substance, the recommendations of the ISSGC report. As it relates to the Cost Benefit Framework, the ISSGC report describes dozens of recommendations for "Cost Benefit Filing Requirements." These are presented on pages 249-250 of the ISSGC report. Table 4.1 summarizes these requirements and provides explanation of how the Black & Veatch evaluation addresses these requirements.

Importantly, the ISSGC report and its recommendations cover seven applications of Smart Grid. The ComEd business case is narrowly focused on one application—the AMI investment. This qualification is important to consider properly the ISSGC report recommendations.

Table 4.1 Treatment of ISSGC Utility Filing Requirements for Costs and Benefits

ISSGC Item	ISSGC Guidance	Black & Veatch Comment
#1) Provide cost-benefit analyses of the investment(s), including a Total Resource Cost test:	The analysis should include any factor (i.e., cost or benefit) that meets the following criteria: • They can be expected to have a meaningful economic impact on the utility's investment decision or are relevant to the Commission's approval decisions. • They can be reasonably and transparently quantified and monetized. • They are relevant to the analysis, specifically including the costs of achieving claimed benefits.	The evaluation meets this requirement. It is comprehensive and detailed in identifying costs and benefits related to the specific attributes of the business case. Certain costs and benefits are deemed out of scope, such as pre-pay meter applications. The analysis does not rely on specific operational deployment plans, but rather assumes a general five-year deployment schedule. By doing so it leaves room for additional economies to be realized. Black & Veatch has experience on many business cases. It judges the scope of costs and benefits included in the ComEd business case reasonable and aligned with other utility efforts.
	Costs and benefits should only be counted once; there can be no double-counting of	The evaluation meets this requirement.

[31] Illinois Statewide Smart Grid Collaborative: Collaborative Report. September 30, 2010. Report compiled by Enernex Corporation. Available at http://www.ilgridplan.org/Lists/Announcements/DispForm.aspx?ID=36&Source=http%3A%2F%2Fwww%2Eilgridplan%2Eorg%2Fdefault%2Easpx

ISSGC Item	ISSGC Guidance	Black & Veatch Comment
	benefits.	
	All costs and benefits used in the analysis should be incremental to the investment when compared with a baseline or "business as usual" scenario. The baseline scenario should reflect the related costs or benefits that would be anticipated if the investment were not made.	The evaluation meets this requirement. The Black & Veatch analysis is structured around scenarios (the "As Is" versus the "To Be"). "As Is" is without automation. "To Be" assumes AMI. Coupled with the two deployment cycles (five and ten year) these results in two *cases*. In all scenarios and cases only costs and benefits that are incremental to ComEd are included. For example, pension and benefit costs were carefully considered to include just true incremental costs, not overhead allocations unaffected by AMI.
	The cost-benefit analysis should recognize as a separate line item any stranded costs that would result from the smart grid investment.	The evaluation meets this requirement. The evaluation includes and accounted for the stranded costs of these assets.
	The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analysis to be filed with the Commission (e.g., TRC, RIM, etc.)	The evaluation includes cost-benefit ratios estimate and discussion.
	Cost-benefit analysis may bundle or package together investments in several applications if those applications are needed to function together or provide otherwise unachievable synergies, or if they are reliant on a common infrastructure investment.	The evaluation meets this requirement. The AMI system analyzed is an end-to-end system involving all required elements of an AMI system. The Black & Veatch evaluation considers the functionality of the Smart Meter system as inseparably composed, including the use of the disconnect/reconnect switch. The evaluation includes one example of how to view separately the disconnect switch feature of the meter in relation to its incremental cost and incremental benefits. The AMI system that is assumed (and built into the cost structure) represents a fully functional smart meter, including the provision of the internal service switch where applicable and reliance on "meter tables" for measurement storage and data retrieval. It also includes the in-premise RF communications ZigBee HAN radio.[32] It also includes a probe for manual meter reading operations when these may be occasionally needed or useful. The RF communications network that is assumed (and built into the cost structure) is

[32] Black & Veatch has seen costs for the provisioning of the ZigBee HAN radio as part of the RF Communications components within the smart meter as low as $1. The ComEd meter deployed for the Pilot includes the ZigBee HAN radio.

ISSGC Item	ISSGC Guidance	Black & Veatch Comment
		likely, in Black & Veatch judgment, to provide important value-added communication capabilities to support future applications in areas of outage management, distribution system asset optimization, and distribution automation communication services.
	To the extent that it is feasible to separate underlying platforms from individual applications, smart grid applications contained within a package should still be subject to individual cost-benefit analysis based on their stand-alone incremental costs and benefits.	The evaluation meets this requirement, to the extent applicable. In Black & Veatch's view, this is more of a hypothetical than practical consideration for the proposed ComEd system described in this evaluation, given the narrow focus on AMI. However, the evaluation includes a description of the cost-benefit relationship of the disconnect switch (as a portion of the meter cost) and the disconnect-related benefits. This description is meant to be illustrative and not exhaustive. The magnitude of the Revenue Management Bad Debt and CIM benefit achievable by the switch, quantified and described in this evaluation, far exceeds the incremental cost of the disconnect switch itself.
	Cost-benefit analysis should provide a calculation of a payback period based on the present value of the annual cash flows of the smart grid investment or package	The evaluation meets this requirement.
	Potential non-regulated, third party, or incidental revenue from smart grid infrastructure investments should be reflected in the cost-benefit analysis.	The business case does not consider non-regulated or third party potential incidental revenue.
#2) Provide documentation supporting the cost-benefit analyses	Documentation of key assumptions underlying the analyses, particularly of those factors that may have a high degree of variability and/or uncertainty	The evaluation meets this requirement. Detailed Benefit Description documents are provided that describe each benefit. Separate document is provided on costs, deployment and other assumptions.
	Discussion of the uncertainties associated with estimates of costs and benefits over the term of the payback period	The evaluation meets this requirement. Uncertainties are described in the evaluation report in the Sensitivity and Recommendation sections.
	Discussion of the potential change in benefits and costs that may occur over time assuming various implementation schedules	The evaluation meets this requirement. The evaluation report includes two deployment scenarios: the five-year deployment and the ten-year deployment. It is important to note that the costs to implement and operate the AMI system vary only minimally between five-year and ten-year deployment scenarios. There is relatively more difference in the estimated benefits with the

ISSGC Item	ISSGC Guidance	Black & Veatch Comment
		switch between a five-year or ten-year deployment. Refer to the subsequent Cost and Benefit sections for more illustrative details. The Black & Veatch evaluation includes careful consideration of the estimated occurrence in time of costs and benefits.
	Identification and discussion of other investments or approaches (if any) that reasonably might achieve similar or better results	The evaluation includes the important consideration of a stretched deployment plan (the ten-year view). It also notes that optimization of the deployment plans may secure additional benefits and lower costs. Outside of these considerations it does not offer other alternative investment approaches (such as selective deployment of smart meter capabilities)[33]. The specific form of the ComEd business model is still evolving. One area for ComEd to evaluate is the long-term pros and cons in the area of the "outsourced" data center operation.
	Documentation of the discount rates used in the analyses and a discussion of the rationale for their use	The evaluation meets this requirement. The Black & Veatch evaluation applies a low-risk discount rate to the estimated change in customer cash flow, reflecting a customer-facing view to these money flows. As such, the Net Present Value (NPV) is based on a 20-year Treasury rate of 4.27%.
	Documentation of a sensitivity analysis of the projected costs and benefits of the investment to variables and assumptions; while reasonable discretion should be provided in terms of the variables and assumptions to be included, the sensitivity analysis should: • Identify the key variables from the cost-benefit analysis that merit sensitivity analysis. The degree of participation, assumed behavioral impacts, and persistence of customer behavior changes should be among the variables included in sensitivity analyses. Other candidates for inclusion are variables (such as emission costs and reliability) that have a wide range of potential values and/or are more subjective in	The evaluation meets this requirement. The Black & Veatch evaluation includes a sensitivity analysis of several key variables. Participation levels are not applicable, since the benefits are not driven by voluntary customer participation. The evaluation includes an estimate of emissions avoided. No sensitivity of this is provided since it is not that large of a benefit and it is a residual of other benefits.

[33] One potential direction ComEd may evaluate is an alternative "spot" deployment of communicating smart meters that specifically target the bad debt, consumption on inactive and UFE-related meter locations. However, because these customer behaviors occur at differing locations at different times, such as move-out occurrences at apartments or homes, Black & Veatch does not believe this would provide a meaningful investment approach.

ISSGC Item	ISSGC Guidance	Black & Veatch Comment
	nature. • Produce cost-benefit results using alternate values for the variables in order to demonstrate the sensitivity/impact various scenarios might have on the economic profile of the smart grid investments.	
	Discussion of the rationale behind the packaging or bundling of applications in the analyses	The evaluation meets this requirement. The business case assumes an aggressive use of the capabilities of the smart meter system to fundamentally re-orient Meter Reading, Field Meter Services, Billing, Call Center, Revenue Management, Revenue Protection, and Outage Management areas of responsibility. Envisioned is an aggressive and sustained series of business process redesigns and impacts that will impact several areas of ComEd's day-to-day operations. At this level of analysis, reasonable estimates are used to estimate benefit occurrence. No separate packaging of applications is assumed. However, the evaluation does include estimates for investments in new IT systems.
	Documentation of the investment's useful life and the basis for its determination	The evaluation partially meets this requirement. Regarding the depreciation assumptions used in the evaluation, depreciation rates are clearly stated for both book and accelerated purposes. Rates are included in Appendix E: Cost Assumptions. Regarding the replacement (aka replenishment) of either current non-AMI meters or new AMI meters in the future, the evaluation and analysis assumes no replacement investment for these assets during the 20-year timeframe of the analysis. While this may under-report total investment and return on rate base, the avoided replacement investment (in non-AMI meters) is also ignored. The evaluation takes no credit, as an avoided investment, of ComEd's replacement of its existing meter asset.
	Documentation of the length of time over which reasonable customer benefits can be reliably estimated	The evaluation meets this requirement. Black & Veatch believes that a 20 year time period for the evaluation is appropriate. Longer time periods do not improve the information value, and involve speculating over a longer time period about costs and re-investment choices. The ComEd business case assumes a permanent restructuring of the operational cost structure (Meter Reading, Field Meter Services, Billing,

ISSGC Item	ISSGC Guidance	Black & Veatch Comment
		Call Center, etc.). These changes drive benefits that are presumed to be permanent. Second, the business case assumes a fundamental change in the Revenue Management and Revenue Protection activities, also resulting in permanent business impacts.
	Documentation of assumptions regarding any environmental benefits incorporated in the analysis (e.g., emissions reduced, values of emissions/allowances)	The evaluation meets this requirement. The reduction in total GWh consumed by the ComEd customer base is assumed to reduce the total amount of energy dispatched to the system. In turn this will drive some reduction in power plant emissions.
	Discussion of the methodology and assumptions used in deriving the estimated benefits from load shape changes. This discussion should describe the model(s) used, model inputs and outputs, model logic (at a high level), scenarios performed, and how model results are to be interpreted.	Except for the minor estimated reduction in total capacity required (43 MW) there are no load shape changes assumed as part of the analysis.

5 ComEd AMI Pilot Project Overview

A key part of understanding the full-scale business case is to recognize the scope of the ComEd Pilot and the influence of the Pilot on assumptions that go into the evaluation.

5.1 Regulatory Background

ComEd first proposed a smart meter project as part of its 2007 rate case. The proposal, as part of *Rider SMP* (System Modernization Project), provided for (1) the recovery of capital costs associated with Smart Grid expenditures between rate cases, and (2) Commission pre-approval of capital expenditures on specific Smart Grid projects. ComEd sought approval of eight Smart Grid projects, including an AMI first phase, a scaled deployment of approximately 200,000 meters in a single geographic location (i.e., a complete operating center). In the final order of ICC Docket 09-0263 issued on October 14, 2009, the Commission approved the AMI Pilot and associated tariffs for the limited purpose of providing recovery of capital costs associated with an AMI pilot (i.e., Phase 0), subject to a six-month workshop process conducted by an independent facilitator. The Order contemplated a 2009 meter and network deployment to focus on the examination of operational benefits; however, subsequent conversations with stakeholders indicated strong support for also examining customer-side and societal benefits.

Following the rate case, and using an independent facilitator, ComEd and stakeholders participated in ICC-sponsored workshops from December 2008 through May 2009 to develop an updated AMI pilot. Discussions focused on the following:

- Where to deploy the smart meters
- How many meters to deploy to get sufficient learning experience about the potential impacts of a full-scale AMI deployment
- What types of in-home technologies, pricing tariffs, and customer education efforts would be useful in order to study customer behavior
- What technical evaluation criteria ComEd should use in its sourcing activities for AMI system vendors

Information about the workshops is available at the ComEd AMI Future website.[34] With the workshops concluded, ComEd filed a revised pilot program in June 2009 to the ICC. In October 2009, ComEd received Commission approval to conduct the pilot program.

5.2 The AMI Pilot Project

As a result of the workshops, ComEd established two primary objectives for the Pilot. First, the Pilot should provide a more rigorous quantification than currently available of the financial attractiveness of full-scale AMI implementation from a utility operating perspective. Second, the Pilot should contribute to a good estimate of the magnitude of energy and peak demand reduction from changes in customer behavior. The purpose of this report is to address the first objective. The second objective will be covered separately through analysis and reporting performed by the Electric Power Research Institute (EPRI).

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[34] See http://comedamifuture.com/.

The original scope of the Pilot is 131,000 electric meters deployed in four distinct geographic areas and eleven municipalities (see Table 5.1).

Table 5.1 Pilot Meter Deployment Locations and Rationale

Location	Objective	# Meters
"I-290 Corridor" All meters in the following nine (9) towns: Bellwood, Berwyn, Broadview, Forest Park, Hillside, Maywood, Melrose Park, Oak Park, River Forest	Validate operational business case. Conduct customer experiments.	100,000
City of Chicago Humboldt Park area Two high rises in downtown loop	Test AMI technology capability. Conduct expanded customer experiments.	30,500
Tinley Park[35]	Test AMR with water meters.	500

Figure 5.1 illustrates the basic segmentation of the pilot participants in relation to all of ComEd's customers. The CAP participants are a subset of the residential customers that make up the majority of the 131,000 AMI participants.

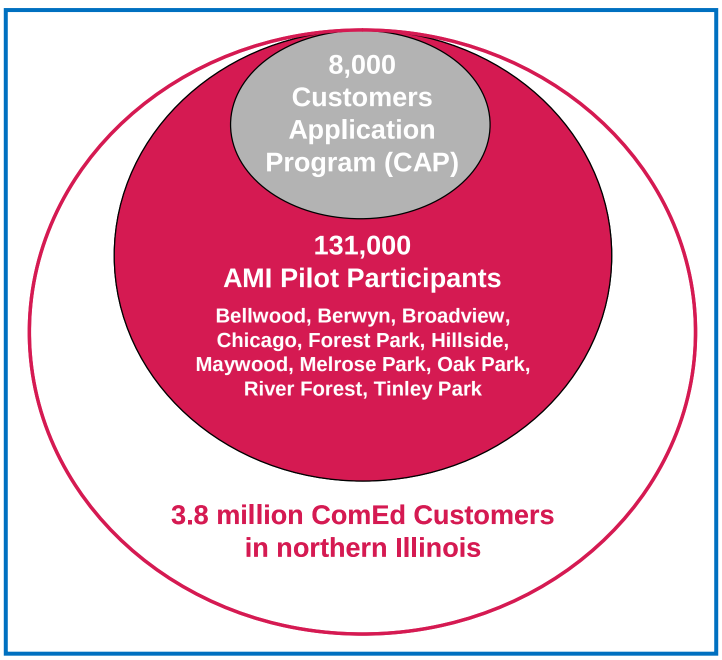

Figure 5.1 Pilot Customer Participants by Program Emphasis

[35] The noted Tinley Park water meters, and all water meters in the ComEd service territory, were excluded from this AMI business case evaluation. Please refer to the AMI Pilot final report submitted to the ICC by ComEd for details.

The schedule of the major aspects of the combined operational and Customer Application Pilot (CAP) program is summarized below:

• Implement IT functionality	February 2009 – May 2010
• Deploy AMI network/meters	November 2009 – May 2010
• Operate AMI network	November 2009 – June 2011 (or on-going)
• One Year of CAP Customer Billing	June 2010 – May 2011
• AMI Business Case, Final Report	January 2011 – May 2011
• CAP Evaluation, Final Report	July 2011 – September 2011

For the Pilot location, ComEd proposed a single operating center for the following reasons:

- Simplified logistics for material staging, field installer reporting, and field project management
- Change management and on-going process management would be more manageable for both field and office process tasks
- A single AMI network geographic "footprint" would limit the AMI communications infrastructure such as Wide Area Network (WAN) costs and RF collection devices
- Simplified maintenance of the pilot system pending the outcome of deliberations with the Commission about expansion of the AMI network to cover more of ComEd's service territory

At the same time, it was important that the operating center selected would be representative as a sample of ComEd's service territory for deployment, cost, and benefit conditions. This would enable the Pilot results to be reasonably extrapolated over the entire service territory.

To determine the best location, ComEd scored and ranked the 19 operating centers based on these criteria. This analysis led to the selection of a single, regional field operating center within ComEd's service territory (the Maywood operating center). Further analysis at the municipality level was performed to identify a single "footprint" of contiguous communities that preserved the ComEd system average characteristics.[36] The nine communities along Interstate 290 met the requirement while capping the total meter count required to approximately 100,000.

[36] A single "footprint" is important since it best approximates the nature of how the "mesh" RF communication network is designed and operated.

6 Smart Meter Requirements and Specifications

As part of business case work related to smart metering and Smart Grid, it is good practice to ensure an alignment of business requirements, functional requirements, and technical and performance specifications. This specification and characterization helps drive cost and benefit discovery, especially prior to any sourcing activity and specific vendor selection(s).

In deference to these good practices, the ISSGC report makes recommendations for any Commission filing regarding Smart Grid technical characteristics and requirements. However, because the merits of the proposed technical solution have been shared by ComEd in other venues (including the Workshop process with stakeholders), the scope of evaluation here does not include a technical review of the ComEd systems (MDMS, AMI communication system, meter installation support systems, applications dependent on AMI data provisioning and system communication, integration, middleware systems) to determine how these systems in part or in whole comply with the ISSGC Report recommendations. Black & Veatch recommends that ComEd separately identify how its selected vendor(s) and systems comply with the ISSGC Report recommendations regarding technical characteristics and requirements to the extent that ComEd and/or stakeholders perceive the existing base of information to be incomplete.

To develop cost data that is consistent with the proposed technical solution, the evaluation gathered specific cost and pricing values provided by ComEd, leveraging available findings and data available from the Pilot. Some information was updated by vendors through confidential communications.

Through experience in sourcing activities for other utilities, Black & Veatch is aware of the technical performance requirements (as described in the ISSGC Report) and many of the capabilities of leading AMI systems in meeting those requirements. Based on detailed technical and performance specifications developed for other utilities, and the ability of leading AMI system vendors to address utility requirements, Black & Veatch assumes that the ComEd system can achieve the necessary level of performance consistent with (a) the ISSGC Report's recommendations and (b) the scope of costs and benefits in this evaluation. To provide a validation of the system capabilities, however, is outside of this report's scope. Also, whether or not the systems can achieve the required levels of performance is significantly tied to the comprehensiveness and rigor of contract provisions, including SLA's and work scopes and the overall quality of rigorous and thorough planning and design work.

Through the stakeholder workshop process, the ComEd AMI project team developed a list of solution requirements for both the AMI solution and the back office. These are listed and described in more detail in Appendix H.

7 Business Case Benefits

The Black & Veatch evaluation includes the specification of approximately one dozen benefits. Many of these benefits are avoided costs. Each benefit is built from a detailed understanding of the proposed business process change that will impact the activity area. Moreover, for each avoided cost a determination is made as to whether the avoided cost impacts operations and maintenance costs or capital costs. Details for each of these benefits are provided in the "Detailed Benefit Descriptions" presented in Appendix F.[37]

The financial impacts associated with AMI benefits are determined by comparing two scenarios. First, the "As Is" scenario is constructed, which extrapolates ComEd's current business structure and cost over time. Second, a "To Be" business scenario is similarly constructed, which estimates the impacts over time of automation. The comparison of the "As Is" and "To Be" scenarios provides the foundation for the discrete *cases* (i.e., the 5- and 10-year business cases).

7.1 Meter Reading

Benefits accrue in the form of avoided operating costs in the area of meter reading. The benefits reflect the gradual reduction in personnel requirements for this area. Included in the evaluation model is avoided direct labor, benefits and pension costs, incentive costs, overheads such as supplies, and vehicle cost reductions. These benefits "ramp in" as manual meter reading requirements decline. A three-month lag between the meter deployment and the benefit occurrence is assumed. Meter reading costs are assumed to grow under the "As Is" scenario to account for ComEd's system growth as well as cost escalation in labor factor inputs. A key assumption for meter reading resources is that meter readers are transferred out of the meter reading department and into other areas of work within ComEd for the duration of the deployment term.

Pilot lessons have been instrumental in understanding how meter reading resources will be affected as the level of automation increases. Lags in benefits are built into the evaluation to account for the duration of the meter certification process. Also, based on Pilot experiences, ComEd assumes that it will be possible to deploy smart meters when the existing electro-mechanical meters fail. This helps avoid replacement work with current electro-mechanical meters. The Pilot has also provided insight into how certain operating centers might be prioritized for deployment, even though this is not a consideration built into the financial analysis at this time.

7.2 Meter Reading Supporting Systems

Directly related to the meter reading cost reductions are the avoided capital costs for information technology systems that support current manual meter reading process. The evaluation estimates that ComEd will reduce, but not fully eliminate, the future investment for hand-held devices and software maintenance fees in support of a manual meter process. The evaluation further assumes that a limited number of hand-held meter reading devices will be retained going forward to support manual reads and

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[37] It is important to appreciate that in developing these estimates, the impacted department managers were responsible for providing the data about the "As Is" and "To Be" activity levels and full time employees (FTE) requirements. To the extent that benefits are not reasonable estimates, it implies that departmental budgets could be impacted. This work was not conducted in a vacuum with disinterested participants. This alignment of incentives to specify the impacts accurately sets the work apart and helps, in Black & Veatch's view, to improve data quality.

probes as necessary (e.g. in the instances when an automated read is not successfully communicated from an AMI meter).

7.3 Automated Meter Reading

Benefits accrue due to the avoidance of communication costs for the existing Automated Meter Reading (AMR) systems that will be taken out of service. These are avoided operating costs. These communication costs are associated with the relatively small number (approximately 6,080) of AMR meters. The AMR systems at ComEd use both dial-up telephone circuits and wireless services. ComEd will reduce these costs with the smart meter deployment. The Pilot validated that it is reasonable for ComEd to assume that it can replace these metering systems with the RF mesh network.

7.4 Field and Meter Services

Benefits in the form of avoided operating costs also accrue in the area of Field Meter Services (F&MS). The Evaluation estimates that there will be declines in resource requirements with automation due to several factors that include the use of the disconnect/reconnect switch capability. The Black & Veatch evaluation has carefully reviewed each F&MS work activity area comparing the activity levels under the “As Is” scenario with the “To Be” scenario. Some work areas decline and others increase. An example of an increase is in the area of field investigations for potential theft and tamper conditions. This classification of “before and after” work is shown in Appendix C.4. When activity levels are known, direct labor and other costs are applied and reductions computed. As with Meter Reading, a three-month lag time is assumed between meter deployment and benefit recognition. The Pilot has provided information about the likely residual requirements for field meter service inspection work with the implementation of AMI. Certain fieldwork will diminish while other fieldwork will increase; however, the net benefit is a reduction in FTE requirements.

The evaluation estimates that there will be *<u>no changes</u>* to the F&MS activity levels that represent capitalized installation labor. The Black & Veatch evaluation assumes that the field work to change out meters under the “As Is” and “To Be” will remain approximately the same. The Pilot has not revealed significant opportunities to reduce certain kinds of inspection activities, as an example. ComEd will continue to investigate the opportunities that the smart meter deployment may offer to reduce required field activities including regulatory compliance work (e.g. random meter samples, periodic meter exchanges, and competitive declaration exchanges).

ComEd will realize a small benefit associated with the salvage of meters that are retired. The meter salvage (a very small benefit in dollar terms) is treated as offsetting operating and maintenance costs. The Pilot has provided information about the removal costs and handling issues with meters removed from the field. ComEd has been able to anticipate likely cross-dock resource requirements associated with a full-scale deployment. Cross-dock operations would handle and process the to-be-retired meters.

7.5 Billing

Benefits in the form of avoided operating costs also accrue in the area of Billing. With AMI automation, ComEd’s average meter read performance will increase from 88% (2010 weighted average across the service territory) to an estimated 99.5% read performance. As a result of this increase in *actual* read performance, as opposed to relying upon *estimated* reads which directly drive billing exceptions, there will be a resulting reduction in Billing FTE required to manage and process these billing exceptions. In the steady state after the full AMI system implementation is completed, there is an estimated reduction of 16 Billing FTE. Through the AMI Pilot, ComEd has been able to directly see the positive impact associated with the reduction in estimated meter reads on accounts within the Pilot footprint. As such, those findings and lessons learned enabled and support the estimation of these FTE reductions.

7.6 Call Center

Benefits in the form of avoided operating costs also accrue in the area of Call Center. While there is an initial estimated increase in call volumes during the AMI meter deployment period, ComEd expects to return to a steady state level, and then realize a minimal net FTE requirement reductions over time. Analysis was performed to estimate the Call Center impact during and post deployment for those primary call types that would be directly affected including: increase in inquiries during deployment, reduction of billing (e.g., cancel/rebill requests) due to increased actual meter read performance, and an increase in collections and disconnection/reconnect requests due to increased revenue management activities. The net estimated impact post implementation is a reduction of approximately 1 FTE. During the AMI Pilot, ComEd trained seven Customer Service Representatives (CSRs) for dedicated effort related to the AMI deployment and operation. While ComEd is currently performing a thorough assessment of Call Center operations from the AMI Pilot, ComEd was able to leverage Pilot findings and call metrics to estimate this net impact. In addition, ComEd has leveraged feedback (re: Call Center impacts) from other utilities that have implemented and are currently supporting AMI.

7.7 Outage Management

Benefits in the form of avoided operating costs accrue in the area of Outage Management. The evaluation assumes that the AMI system will allow for fewer trips to premises for what are referred to as “single lights out” field trips. The AMI system has the ability to provide near real-time outage status for the electric meters. The meters provide power status information in two ways—automatically and upon request. The automatically generated information includes the power fail indication upon loss of power by the electric meter and power restoration indication upon restoration of power at the meter. Additionally, the AMI system provides the capability for a user or application, such as the Outage Management System (OMS), to generate an on-request service to query the power status of a particular meter or group of meters.

Because of this, it is anticipated that ComEd will experience fewer "OK on Arrival" occurrences (i.e., customers that had a power outage that was restored on a separate, previous outage ticket) and will not need to send a first responder to the field needlessly to address customer outage tickets that result in positive power status verification. ComEd will now be able to ascertain near real-time power status via a query to the AMI system or via automatically provided power status indication that will more accurately reflect the current state of restoration activity and allow resources to be utilized more efficiently. This will also reduce costs to call customers to confirm power restoration.

7.8 Outage Management—Improved Efficiency During Storms

Additionally, since the AMI system has the ability to provide near real-time outage status for the electric meters as discussed above, the information can be used to more accurately reflect current outage conditions during major storm events. Maintaining accurate, current outage assessment and repair activity information represents the biggest challenge during storms. With the ability to automatically, or on-request, receive outage information from meters throughout the system, the ComEd OMS can more effectively track and manage the actual outage conditions. This translates to improved internal and external outage communications with the Storm Center. Through a better understanding of the state of the system during major storms, ComEd should be able to more effectively deploy and coordinate emergency restoration resources. This should translate into decreased time allotted for storm restoration and savings in overtime and contractor expenditures.

While the AMI system was not directly connected to the OMS during the AMI Pilot, the performance of the outage events was monitored and demonstrated to be sufficient to provide the capabilities envisioned in this benefit. Additionally, during the Pilot duration, the ComEd AMI team was able to effectively leverage the AMI functionality, specifically the ability to "ping" the meters during storms to determine if particular premises were still out of power or if power had been restored. On eight different dates, ComEd "pinged" meters at end of storms to confirm status of single outage tickets. 272 out of 359 customers were confirmed to have power and therefore the outage ticket could be closed without incurring the time and cost of sending a truck to the location to verify.

7.9 Unaccounted for Energy (UFE)

The evaluation includes estimates for the reduction in Unaccounted for Energy (UFE), specifically in the areas of theft and tamper conditions. Its occurrence has two effects, depending on the reaction of the customer where the theft/tamper condition is located. If that customer elects to reform his or her behavior and begin paying for service, ComEd will then begin receiving from these new customers the revenues that are currently "socialized" and paid by current customers. This is assumed for the majority of the customers where a theft/tamper condition is noted. Some customers and meter locations, however, will not fall under this treatment. In these instances, ComEd will disconnect service to such customers so as to avoid power purchase costs, while distribution system costs (and revenues) will remain unchanged. [38] An illustration of the estimated UFE benefit is presented in Appendix C.7, illustrating how the benefits are driven from a combination of energy and delivery service revenues as well as avoided power purchase costs.

7.10 Consumption on Inactive Meter (CIM)

The evaluation includes estimates for the reduction in consumption in energy from inactive accounts known as CIM (Consumption on Inactive Meter). A wide range of situations gives rise to this form of consumption. Some result from the inherent challenges of managing 700,000 move-in and move-out orders each year. The Revenue Protection group targets 100% of the CIM locations, but there are limits within Revenue Protection and Field Meter Services on how many locations can be investigated and disconnected. Through the use of the automated disconnect/reconnect switch, ComEd estimates it will be able to greatly reduce the occurrence of CIM.[39] For this evaluation, it is assumed that there is no reduction in consumption as a result of this new business practice (connecting and disconnecting at time of move-in and move-out), but instead

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[38] Both effects will flow to customers as benefits and are included in the computation of net customer impacts. However, in the case of new revenues, the number of billing units used to create rates will change. For customers to fully capture this benefit, it will be necessary to reflect the revised number of billing units in rates.

[39] It is estimated that a small percentage of meter locations (5%) will not have a remote disconnect switch (due to the nature of the meter at that location).

that this new business practice results in the ability for ComEd to correctly bill and collect new revenues. An illustration of the estimated CIM benefit is presented in Appendix C.8, illustrating how the benefits are driven from a combination of energy and delivery service revenues. Unlike the estimated UFE benefit, since it is assumed that there is no consumption reduction associated with CIM, the CIM benefit does not include any avoided power purchase costs. However, sensitivity analysis was performed to understand the impact to the business case evaluation if there was a resulting reduction in consumption as part of CIM. This is presented in Section 10.

During the AMI Pilot, ComEd was able to remotely disconnect a number of meters that had consumption but had no account for billing/payment purposes. As a result of this effort, ComEd was able to 1) confirm the success of the remote disconnect/connect capability, and 2) also understand that a large percentage of these current customers will translate into paying customers in the future once AMI solves the issue of consumption on inactive meters.

7.11 Bad Debt

The evaluation includes estimates for the reduction in bad debt. By using new business practices in conjunction with the disconnect switch automation, ComEd estimates that it will be able to cut off services in a more timely manner because back office and field work capacity constraints will be reduced. Additionally, the technology allows for customers to be restored in minutes after payment is received as opposed to up to two days under current limitations. Potentially, additional working capital benefits associated with this reduction exist as well, but these are not contemplated in this report in terms of their potential impact to alter ComEd’s capital requirements.

Table 7.1 Benefits Summary

Benefit	Description[40]	Steady State 2017 Value (Post 5-Year Deployment)	20 Year Cumulative Value
Reduction in Manual Meter Reading Expenses	An Operations and Maintenance (O&M) avoided cost	$53.5 million	$1,124 million
Reduction in Field Meter Services (F&MS) Expenses	O&M avoided cost.	$15.4 million	$335 million
Reduction in Billing Department Expenses	O&M avoided cost.	$2.8 million	$75.5 million
Reduction in Call Center Expenses	O&M avoided cost.	$120,000	$3.1 million
Reduction in Outage Management Expenses	O&M avoided cost.	$4.2 million	$87.4 million
Avoided Capital Expense, Meter Reading Systems	An avoided cost in replacement capital to upgrade these systems over time.	N/A	$3.4 million
Reduction of Consumption on Inactive Meters (CIM)	Represents incremental new revenues from customers who are identified and pay required bills. This increase in revenue results in an overall *decrease* in costs across all customers.	$65.0 million	$1,343 million. ($469 million in additional Delivery Services Revenues and $874 million in additional Energy Revenues).
Reduction in Unaccounted for Energy (e.g., theft and tamper conditions)	A portion of this benefit represents avoided energy costs. Another portion represents incremental new revenues from customers who are identified and pay required bills. This increase in revenue results in an overall *decrease* in costs across all customers.	$47.6 million	$979 million ($708 million in avoided energy costs; $95 million in additional Delivery Service Revenues; $177 million in additional Energy Revenues).
Reduction in bad debt expense.	This benefit results in an overall *decrease* in costs across all customers, collected through ComEd Rider UF.	$38.3 million	$791 million

7.12 Benefit Realization Schedules

With the deployment of AMI meters throughout ComEd's service territory, benefits can begin to be achieved through the utilization of AMI communication technologies, supporting IT platform, and re-

[40] Benefits are influenced by system growth and escalation due to price movements and changes in the economy. The analysis is based on nominal dollars, so over time all cost and benefit values are adjusted to account for escalation.

engineered business processes.[41] However, due to dependencies on supporting IT and/or business process capabilities, each benefit may follow a different realization schedule. Table 7.2 shows the "lag" period between the meter deployment schedule and when the benefits can be realized. Across all of these benefits, 100% are expected to be achieved no later than one year after completion of the full AMI deployment.

Table 7.2 Benefit Realization Schedule

Benefit Category	"Lag" – Relative to AMI Meter Deployment	Rationale
Meter Reading	3 Months	Communications with the meter and certification will take about 3 months
Field and Meter Services	3 Months	Communications with the meter and certification will take about 3 months
System Billing	1 Year	Stabilization of billing system by balancing installation and billing success rates achieved with the AMI system
Call Center	1 Year	Initially the Call Center reps will have to learn to handle the new call types. In the first year of installation the additional handling time costs will equal the expected benefits
Outage Management	3 Months	Reliable communications and new business practices with the meter will be necessary to realize these benefits
Revenue Protection - Consumption on Inactive Meters (CIM)	3 Months	Reliable communications and new business practices with the meter will be necessary to realize these benefits
Revenue Protection - Unaccounted for Energy (UFE) (theft / meter tampering)	1 Year	Additional software, additional FTEs, and new business practices will be required to realize this benefit
Revenue Management -- Bad Debt Expense Reduction	1 Year	CIMS enhancements, additional FTEs, and new business practices will be required to realize the benefit

[41] The evaluation makes no assumptions about the timing of regulatory processes which are otherwise required for some benefits to be fully captured by customers. The resulting net customer impact (Table 1.1 and Appendix D.5) assumes that all benefits are available to customers when they are achieved through the system operation and the new business processes.

8 Business Case Costs

The Black & Veatch evaluation includes descriptions and estimates of the major cost elements associated with the AMI implementation and on-going support. Costs are decomposed by general area (meter, communication system, IT, and management/other), by type (capital and O&M), and by year (2011 – 2030). Costs (like benefits) are expressed in nominal dollar terms. Escalation and system growth assumptions are factored into each cost item (either included or excluded depending on the cost item). Two escalation-rate assumptions are used (either a labor/services rate or materials rate). The timing of the cost occurrence is based on a review and determination for each cost element. Many costs are scaled with meter deployment. Capital is depreciated for recovery purposes based on individual depreciation schedules on both straight-line terms (book) and accelerated terms (tax). A summary of the 20-year cumulative nominal values for each of these cost categories is listed in Table 8.1.

Table 8.1 AMI Cost Summary

Cost Category	Description	Capital Investment (20 yr cumulative)	On-going O&M (20 yr cumulative)	Total Expenditure (20 yr cumulative)
AMI Meters	Physical AMI Meter (and supporting labor) to be installed at each premise/location	$752 million	N/A – Accounted for in F&MS operational costs	$752 million
AMI Communications	AMI Network Infrastructure to support communications from the AMI meters to "head end"	$107 million	$161 million	$268 million
IT Platform	IT platform/systems to enable and support AMI system	$92 million	$341 million	$433 million
Management (PMO and AMO[42])	Management of project during deployment/implementation and on-going AMI Operations	$45 million	$163 million	$208 million
	Total	**$996 million**	**$665 million**	**$1.66 billion**

Approximately 89% of the capital investment occurs during the first six years (2011 - 2016) of the deployment period.

A 20-year analysis period is used. This choice is discretionary. There are positive and negatives for shorter and longer time periods. One of the negatives of a longer time period is that the cost assumptions become increasingly speculative. The analysis requires assumptions about labor and capital cost items in a far distant future. Also, technology changes over time. The business case analysis represents a fixed snapshot in time (today) around an assumed level of benefits (tied to merits and capabilities of the technology modeled). Over time it is likely that technology will improve, and provide more capabilities at potentially lower or higher prices. Such considerations are outside of the analysis, however, as they are highly uncertain.

[42] PMO stands for "Project Management Office." The PMO oversees the entire program during its implementation. It ensures the hand off of responsibilities over time to the operations group. "AMO" stands for Advanced Metering Operations and pertains to the ComEd organizations responsible for the operations of the AMI system.

Depending on the nature of the changes, this uncertainty could represent downside risk (the system becomes obsolete) or upside risk (the technology platform enables more and more innovative solutions to current and emerging business requirements). The best that can be done is to assume fixed levels of capabilities (e.g., benefits realization) as a way to isolate the opportunity immediately available today. Some of this uncertainty is reflected in the discussion on sensitivities elsewhere in this report.

The costs also include certain overheads, but only if these represent true incremental costs. Sales taxes are included (at two different rates to account for an enterprise zone adjustment). ComEd's internal (incremental cash cost) overheads for Supply Chain support are included. These costs are included in the costs for the cross-dock and meter handling. Costs are also based on vendor unit prices based on Pilot experience and vendor contracts. Black & Veatch has not reviewed these contracts to verify their specific terms and whether these terms apply to the full-scale deployment over extended time periods, but ComEd warrants the reasonableness of the vendor-provided pricing as useful and germane estimates for purposes of the business case.

There are considerations not taken into account, which follow.

First, no effort has been made to align cost occurrence with the specifics around cash management of vendor receivables (ComEd payables). There is some inherent change this detailed budgeting might reveal, but it is insignificant for purposes of a 20-year analysis. The analysis does not consider these timing issues.

Second, the costs ignore at this stage of the analysis important considerations around re-investment cycles. Once an asset is fully depreciated it is reasonable to assume that there will be capital costs associated with "replenishment." In the area of IT costs this has been taken into account. This replenishment is ignored, however, in the case of smart meters (and their installation costs).[43] Given the 20-year evaluation time period, this lack of a replenishment cycle has marginal influence. Further, the evaluation is consistent in the fact that future replenishment of current, non-AMI meters is also excluded, and therefore not recognized as a benefit in the evaluation. Nonetheless, further analysis may be performed to understand the business case impact of incorporating this meter replenishment into an evaluation.[44]

Third, the costs do not account for the ComEd AMI Pilot costs (either capital or operating and maintenance) incurred as of and through April 2011. The analysis does assume, however, $6.4 and $3.2 million of ongoing Pilot operations and full-deployment implementation costs for the balance of 2011, in the areas of IT and Customer Operations respectively.

The expression of costs is shown in Appendix D.3 which includes a detailed list of annual costs, both capital investments and O&M, for the 20 year evaluation period. These costs refer to the five-year deployment scenario. The Black & Veatch evaluation accommodates clear visibility into such activities and cost areas as

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[43] As noted elsewhere, the "replenishment" is also ignored in relation to the current meter "fleet," so to some degree there is an offsetting avoided cost also not taken into account.

[44] One technique is to recognize higher levels of failures in equipment in outer years. Or, the analysis can assume an explicit assumption about a re-investment cycle. However, these arguments need to take into account both costs and avoided costs.

the on-going smart meter replacement work due to routine and expected failures.[45] This on-going capital work, however, is assumed elsewhere in the model.[46]

The cost structure assumes various roles and responsibilities for ComEd resources and ComEd suppliers. These are summarized in Table 8.2. Changes to these assumptions may impact the resulting cost estimates.

Table 8.2 Implementation Support Services

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Business Case Cost-benefit Analysis
Meters (including shipping, handling, insurance, freight, testing, warranty support)	Vendor provided.	ComEd Pilot. Estimates from Vendor contract pricing.
Initial (core deployment) Meter installation work (including minor repair work, and call center appointment scheduling)	Provided by ComEd personnel and supplemented with field installation contractor.	ComEd Pilot analysis.
On-going smart meter replacement work	ComEd personnel provided.	ComEd Pilot experience for failure rates and for provisioning work order systems to manage fieldwork orders.
Handheld systems for meter exchanges	Vendor provided hardware and software components. Configuration and integration work required.	ComEd Pilot experience.
RF Communications planning and design and implementation	Joint. Support services from RF communication systems vendor; significant ComEd implementation team roles and responsibilities.	ComEd Pilot experience. Estimates from Vendor contract pricing.
RF Communication hardware requirements	Vendor provided.	ComEd Pilot experience. Estimates from Vendor contract pricing.
Miscellaneous equipment for RF Communication hardware mounting requirements.	Vendor provided.	ComEd Pilot experience and experience mounting and maintaining distribution equipment.
Lease costs for some number of third party sites to mount RF equipment.	ComEd to manage, locate premises, negotiate agreements, and install.	ComEd experience in maintaining its distribution system. Pilot experience.

[45] The analysis assumes a smart meter failure rate of 0.5% per year. Moreover, due to extended warranty coverage, ComEd assumes that upon failure, and for the extended warranty period, ComEd would be responsible for field installation replacement work, not any costs of the smart meter itself, which would be shipped back to the manufacturer for diagnosis, repair and/or replacement.

[46] The evaluation analysis reflects the incremental changes to the ComEd Field Meter Services budget due to AMI implementation. Capital work within this budget changes in nature with AMI. The net change of all capital work within the FMS budget area is reflected as a separate line item in the model. This line item includes the effects of smart meter field replacement work due to routine smart meter failures.

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Business Case Cost-benefit Analysis
AMI Data Center Setup, Software acquisition, and on-going software maintenance.	ComEd's AMI communication systems vendor to provide an "outsourced" AMI data center solution.	ComEd Pilot experience. Vendor price estimates.
AMI System Operations	ComEd's AMI communication systems vendor to provide an "outsourced" AMI data center solution service, referred to as "Software as a Service" or SaaS.	ComEd Pilot experience. Vendor price estimates.
AMI System Software On-Going Maintenance	ComEd's AMI communication systems vendor to provide an "outsourced" AMI data center solution.	ComEd Pilot experience. Vendor price estimates.
AMI RF communication System field Maintenance	ComEd personnel provided.	ComEd Pilot experience. Vendor contract prices for replacement devices.
AMI RF communication "backhaul" WAN communication services	Public digital cellular communications provider, such as Sprint or Verizon.	ComEd Pilot experience.
IT MDMS implementation costs[47]	IT vendors provided.	ComEd Pilot experience. Vendor contract prices. Vendor price estimates.
IT "middleware" applications and systems implementation costs	IT vendors provided.	ComEd Pilot experience. Vendor contract prices. Vendor price estimates.
IT systems integration work.	IT vendors provided.	ComEd Pilot experience. Vendor contract prices. Vendor price estimates.
IT hardware environment to support MDM and middleware	Joint. Vendor to provide hardware. IT to install and operate.	ComEd Pilot experience. Vendor contract prices. Vendor price estimates.
IT operational personnel to manage and run MDM and Middleware systems	ComEd personnel provided.	ComEd Pilot experience.
Information systems costs to support new business practices associated with theft, tamper and other forms of unaccounted for energy losses.	ComEd personnel and IT vendors jointly provided.	ComEd and vendor price estimates.
AMI Operations	ComEd personnel provided.	ComEd Pilot experience and ComEd business planning.
Web-based energy information services	IT vendor provided.	ComEd Pilot experience and vendor price estimate.

[47] The IT model costs are summarized for all the IT systems into general categories (Hardware, Services, and Software). The IT cost assumptions, documented in the Cost Inputs Assumptions appendix, provide detailed assumptions for the underlying systems and components, such as MDMS implementation and Middleware requirements.

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Business Case Cost-benefit Analysis
Project Management Office (PMO) to support design, program planning, business process design, change management, vendor and internal work scope development, contracting, contract management, performance measurement, etc.	ComEd personnel and IT vendors jointly provided.	ComEd Pilot experience, vendor price estimates and ComEd business planning.
Supply Cross Dock (facilities set up, supply provisioning, IT system support, meter receiving and testing, work force provisioning, vehicle fleet management)	ComEd personnel provided.	ComEd Pilot experience and ComEd business planning.
Customer experience	ComEd personnel provided.	ComEd business case estimates. ComEd Pilot experience.
External communications.	ComEd personnel and IT vendors jointly provided.	ComEd business case estimates. ComEd Pilot experience.

9 Business Case Results

This evaluation describes two AMI meter deployment schedules, leading to two separate cases. One is over a five-year period (2012 - 2016). The other is over a ten-year period (2011 - 2020). With both cases, the AMI system drives large operational improvements. Automation reduces operational costs in the following departments: Meter Reading, Field Meter Services, Call Center, Billing, and Distribution System Operations. The evaluation assumes that ComEd will use the system to deliver benefits by (a) reducing bad debt, (b) reducing the number of and consumption at inactive accounts, and (c) reducing UFE associated with theft and tamper. To achieve these results, ComEd will incur new capital costs for smart meters, the RF communications network, various IT systems, and implementation services, as well as the on-going operational expenses.[48] These benefits do not depend on demand response-related customer behaviors.

9.1 Five-year Deployment Results

While the spreadsheet model contains important details, it is useful to view results at a summary level. The AMI implementation requires capital expenditures of approximately $885 million (nominal dollars) over the five-year deployment term.[49] During the deployment period (2012 - 2016) ComEd will spend an additional $157 million on O&M expenditures to support the planning, design, implementation, and initial operations work. Summing capital and O&M, ComEd will invest and spend $1,042 million, or around $260 per ComEd meter (household). During this initial period (thru 2016), total operational, energy procurement and bad debt, and revenue benefits total less than $400 million.

Once the system is fully installed, benefits greatly exceed costs. In year 2017, once deployment is completed, ComEd will incur annual outlays related to the program of approximately $35 million ($30 operating expenses and $5 million in capital outlays). However, at this time, the system is able to generate substantial savings of over $220 million annually. A portion of this is reduced operational expense ($76 million), a portion of this is reduced bad debt and power purchase costs ($73 million), and a portion is higher revenues ($78 million) due to increased billings associated with CIM and UFE. Ignoring the other benefits (reduced energy procurement and bad debt, and revenues), the relationship of strictly the ComEd operational benefits and costs is $76 million versus $35 million; the difference of approximately $40 million may not represent enough cost savings to pay back the initial investment over a reasonable time period, so consideration of the additional benefits is material.

These expenditure and benefit (revenues and avoided costs) patterns of the AMI investment are represented in Figure 9.1. The initial costs will have to be paid for by operational and other forms of savings that fully “kick in” once the system is deployed. In the ten-year scenario these relationships basically remain the same, although the “ramp up” to the steady state takes five years longer. From a present value perspective, this “stretching out” of costs and benefits tends to reduce the overall project value, by around 15%. While imprecise, it is possible to view this relationship as largely linear. A one-year delay reduces overall project value by 3%.

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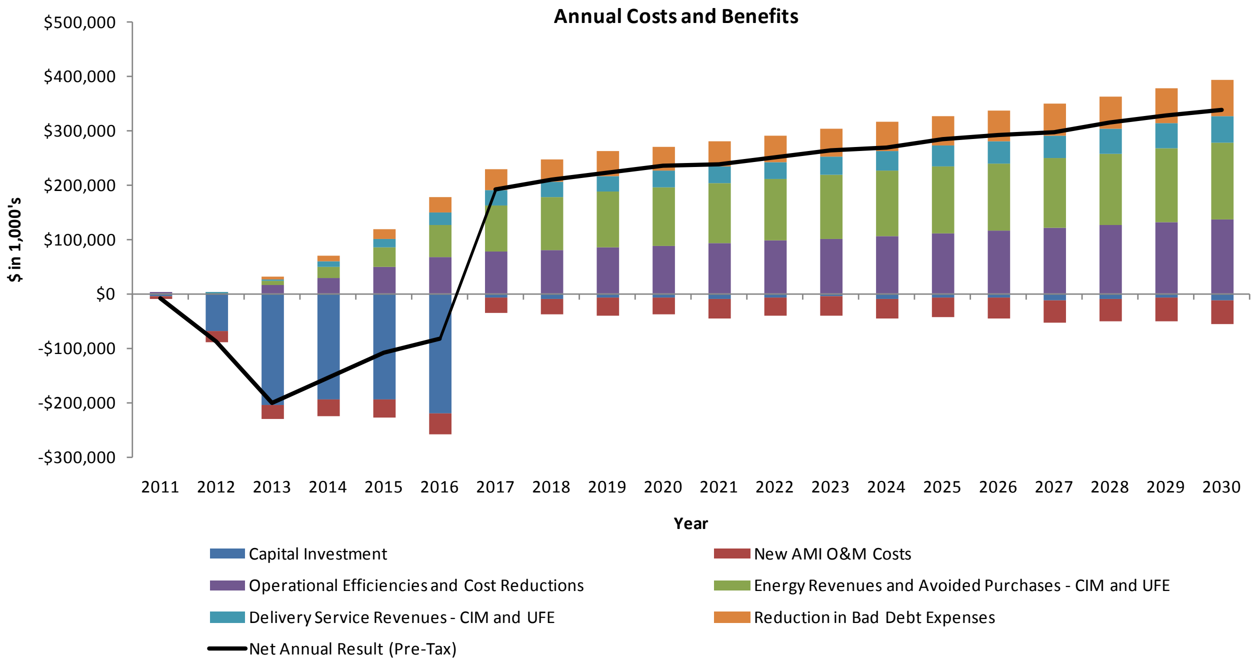
[48] The evaluation excludes benefits and costs associated with (a) the sunk costs associated with the AMI Pilot, and (b) any demand response benefits.

[49] The model includes planning work starting in 2011 - 2012. The five-year deployment cycle begins in the fourth quarter of 2012 and is complete at the end of 2016. The entire 20-year period is defined as 2011 – 2030.

Figure 9.1 Capital Investment and On-going Costs and Benefits (Five-year Deployment)



The AMI system, once deployed, generates substantial savings. However, these evaluation results do not take into account additional analysis refinements, including: (a) impacts on this analysis on depreciation rates should they change from the current assumptions, and (b) reinvestment or replacement of deployed assets retired during the analysis period, if any. The evaluation also does not reflect the impacts of potential schedule changes that delay benefits or accelerate costs. Similarly, it does not reflect any contingency that addresses potential variance due to the inherent uncertainty in the cost and benefit parameters. Some of these effects are addressed in Section 10, Sensitivity Analysis.

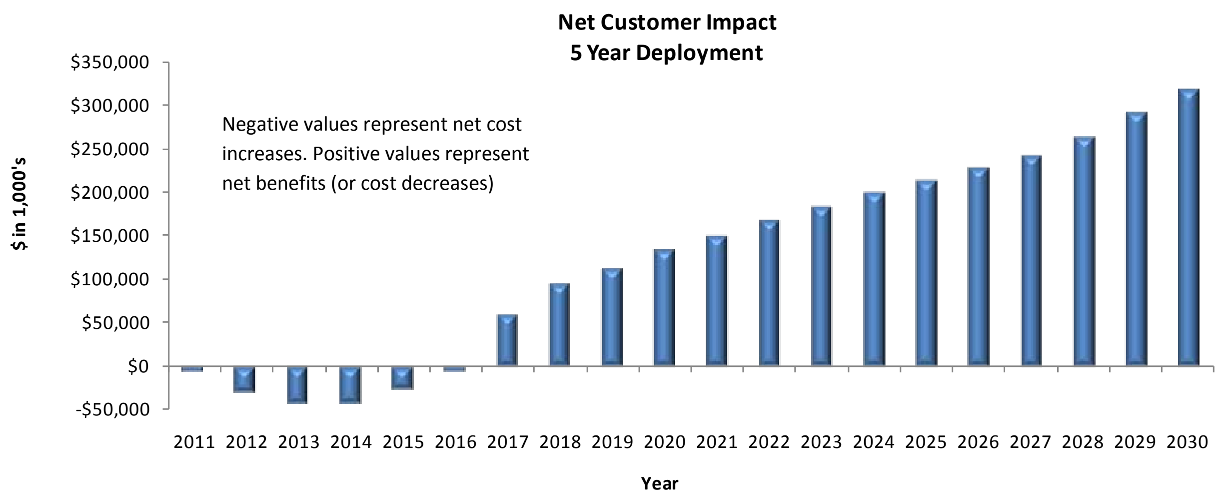
Results are expressed several ways. First, the impact on ComEd's customers is shown and illustrated in Figure 9.2. This represents the money flows ComEd's customers could expect through the AMI program assuming the realization of all estimated costs and benefits. These are strictly the incremental impacts to ComEd's existing business associated with the AMI program. If customer costs increase (illustrated as negative values in Figure 9.2), this represents a need, as part of this program, to collect more from customers (increase rates). If customer costs decline (illustrated as positive values in Figure 9.2), this represents opportunity to reduce rates. This view of the net customer impact includes the necessary allowances for taxes paid by ComEd, depreciation, and return requirements.

This analysis makes no suggestions or assumptions about the nature and timing of how ComEd, the ICC, and stakeholders would consider these changes. Rather, implicit in this analysis is the assumption that each and every year rates would be adjusted to the level required to produce savings estimated for that year.

Over the 20-year analysis period, the net customer impact, assuming a five-year deployment, is approximately $2,493 million. This means that ComEd's customers are saving money (if rates are adjusted to capture all savings). This equates to an average savings of approximately $30 per customer per year.

Second, it is useful to view the yearly net customer impact in terms of its Net Present Value (NPV). Using a discount rate of 4.27% (20-year Treasury Rate), the net customer impact NPV over the 20-year evaluation period is $1,296 million. In terms of today's dollars, this is the value of the program to the ComEd customer, to the degree the discount rate is appropriate, the cost and benefit assumptions accurate, and rates adjusted to allow all the benefits to be captured.

Figure 9.2 Estimated Net Customer Impact



Third, results can also be represented in terms of a payback period. For the simple view of costs and benefits (Figure 9.1)[50], the benefits begin to exceed costs in year seven, 2017. The cumulative benefits exceed costs in year ten, 2020. In considering the net customer impact "cash flow" view, the customer sees positive value in year seven, 2017. It then takes just over one more year when enough positive value (cumulative) has flowed back such that the total net impact to the customer is positive. This occurs in year 8, 2018, and represents the discounted payback period.

Fourth, results can also be shown in terms of several benefit cost ratios. These are often used to express the attractiveness of demand-side programs, and their applicability to AMI is somewhat unique. The benefit-cost ratios are discussed separately in Section 9.3.

[50] The simple view ignores the effects of taxes, depreciation, return and other utility accounting requirements.

Table 9.1 Financial Highlights and Summary — Five-year Deployment

Item	Base Case (Five-year Deployment)
Costs (Cumulative 20 years)	
O&M Expense for AMI System	$665
New Capital Investment for AMI System	$996
Sub-Total	***$1,661***
Operational Benefits & Delivery Service Revenues (Cumulative 20 yrs)	
Operational Efficiencies and Cost Reductions	$1,625
Avoidance of Capital Expenditures	$3
Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$564
Sub-Total	***$2,192***
Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cumulative 20 yrs)	
Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM[51]	$708
Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$1,051
Reduction in Bad Debt Expenses	$791
Sub-Total	***$2,550***
Total (Cumulative 20 years)	
Benefits Less Costs	**$3,081**
Net Impact to Customer	
Net Present Value (NPV)	***$1,296***
Discounted Payback Period (Years)	**8 years**

All $ values in Millions. NPV based on discount rate = 4.27% (20-year Treasury rate).

9.2 Ten-year Deployment Results

Table 9.2 summarizes the results of the ten-year deployment case. The basic relationship of costs and benefits is similar to that shown in the five-year case, although the costs are stretched out over a longer deployment time period and the realization of benefits is delayed. However, certain costs are assumed to occur in the same periods as the five-year case. For example, the IT infrastructure investment occurs at the same level and pace as in the five-year period because it is assumed these investments are required in scale in a relatively compressed time period. Certain implementation costs associated with IT cannot by their nature be strung out over a ten-year meter deployment cycle. Also important, the meter pricing assumption for the ten-year case is not changed. This is a speculative assumption. There are many reasons why meter pricing could be either lower or higher than the five-year deployment case. Much will depend on the nature of ComEd's contracts with meter suppliers and its chosen RF communication systems provider.

[51] Energy purchased power costs include power costs, transmission rights, and other related energy costs.

Table 9.2 Financial Highlights and Summary — Ten-year Deployment

Item	Base Case (Ten-year Deployment)
Costs (Cumulative 20 years)	
O&M Expense for AMI System	$653
New Capital Investment for AMI System	$1,031
Sub-Total	***$1,684***
Operational Benefits & Delivery Service Revenues (Cumulative 20 yrs)	
Operational Efficiencies and Cost Reductions	$1,539
Avoidance of Capital Expenditures	$3
Collection of Delivery Service Revenues Due to Reduction in UFE and CIM	$531
Sub-Total	***$2,073***
Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cumulative 20 yrs)	
Reduction in Energy Purchased Power Costs Due to Reduction in UFE and CIM[52]	$667
Collection of Energy and Other Revenues Due to Reduction in UFE and CIM	$991
Reduction in Bad Debt Expenses	$745
Sub-Total	***$2,403***
Total (Cumulative 20 years)	
Benefits Less Costs	***$2,795***
Net Customer Impact	
Net Present Value (NPV)	***$1,152***
Discounted Payback Period (Years)	**9 years**

All $ values in Millions. NPV based on discount rate = 4.27% (20-year Treasury rate).

The focus of the evaluation, as summarized above, is on a set of narrow, "operational" benefits. The AMI infrastructure contemplated is foundational to other programs and benefits, such as demand response initiatives, net-metering demands of plug in electric vehicles, distribution system asset monitoring and control, load control opportunities, and numerous other possibilities. This evaluation does not describe or speculate on the nature, timing, or scope of these add-on initiatives. It is reasonable to assume that these additional programs will add value to the business case, but they are subject to separate efforts.

9.3 Benefit – Cost Ratios

The application of a specific benefit-cost ratio test can be useful when evaluating energy efficiency measures, but has more limited value in the context of the proposed AMI investment. Ratios are useful when evaluating a portfolio of potential energy efficiency projects and gauging relative attractiveness. The AMI program described here is estimated to drive energy savings to the degree that various forms of behavior associated with bad debt, consumption on inactive, theft, and tamper conditions are reduced. But

[52] Energy purchased power costs include power costs, transmission rights, and other related energy costs.

AMI also enables other programs and benefits; so one challenge is isolating effects and ascribing a certain domain of costs and benefits to specific areas of the business case. Also, more generally, it is the essence of comparison that drives the usefulness of the ratios. The applicable question becomes "as compared to what?" (i.e., what alternative projects might achieve similar results). In this case, the alternative being compared is the "As Is" scenario where there is no investment in AMI.

Notwithstanding these limitations, a Total Resource Cost (TRC) benefit ratio can be constructed, which compares the "As Is" and the "To Be" scenarios and uses the spreadsheet model results. The results here apply to the five-year deployment assumption, and use cumulative values over a 20-year analysis horizon:

- Total energy and capacity related savings = $708 million (avoided energy purchase costs)
- Additional resource savings = $2,425 million (O&M savings, avoided capital, avoided bad debt expense)
- Incremental system costs and overheads = $1,661 million (capital and O&M)

Here, the overall ratio of benefits to costs is 1.88, meaning benefits exceed costs. On a net present value basis, the ratio of benefits to costs is 1.07. These results ignore the additional effect of the incremental new revenue, which ComEd will receive once certain customers are properly billed (UFE, CIM). Including these benefits further improves the TRC ratio. However, the TRC ratio, as with other DSM ratio tests, does not contemplate increases in revenues as a positive impact (whereas in this evaluation the increase reflects the reduction in socialized losses, and thus a benefit to all ComEd customers).

To the extent that additional value could be created due to societal impacts (the Societal Test), the benefit-to-cost ratio would improve. Examples include the value of the emission reductions due to reduced power plant emissions and vehicle miles of travel, and reduced injuries and accidents. As explained in the report, however, the total monetary value of these additional benefits is speculative since today the price of carbon emissions is speculative.

Note that the Participant Test is not applicable. It can be useful when evaluating the participation of customers in a demand side management program.[53] Also, the RIM or rate payer impact measure is largely summarized in the estimated net customer impacts result, which is favorable to ComEd customers.

9.4 Comparison with ComEd Earlier Results (2008)

The findings presented here update and modify the results ComEd offered to the Illinois Commerce Commission (ICC) and its other stakeholders as part of 2008 rebuttal testimony and presented during 2009 workshops.[54] For convenience, figures are rounded to nearest $ million.

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[53] "The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates. For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation. These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits." The California Standard Practice Manual, Economic Analysis of Demand Side Programs and Projects, The Governor's Office of Planning and Research, July 2002, page 9.

Table 9.3 Comparison with Earlier Results (2008)

Item	B&V Evaluation ($ million)	2008 ComEd Evaluation ($ million)	Percent Difference
Capital Costs	$996 million	$800 million	24%
Typical steady state year operational costs	$30 million	$20 million	50%
Typical steady state year Departmental operational benefits (excludes bad debt)	$76 million	$64 million	21%
Additional benefits tied to CIM, UFE, and bad debt expense reductions	$151 million	$63 million	139%
NPV of all costs and all benefits (net customer impact)	$1,296 million	$28 million	-
Discounted payback period	8 years	16 years	-

Costs

- The earlier business case estimated one-time capital costs of approximately $800 million. This evaluation estimates $996 million over the 20 year evaluation period. The capital costs are higher than the original primarily due to increases in the following areas: cost to install, AMI vendor support, meter handling, program management, Home Area Networking communications, AMI Operations, and the overall meter count.
- On-going operational costs were previously estimated at $20 million per year. This evaluation estimates steady-state period costs of approximately $30 million due to increased costs in IT, vendor, and operational support.

Benefits

- The earlier business case estimated annual operations and maintenance benefits of approximately $64 million. This Black & Veatch evaluation estimates annual operations and maintenance benefits of $76 million in steady state year 2017[55], after deployment is completed. This difference is driven primarily by increases in labor cost estimates partially offset by a lower pension and benefit cost.
- This evaluation estimates a higher benefit value for CIM and UFE primarily due to an increase in revenues. In the previous business case, only avoided energy purchases associated with CIM and UFE were included. ComEd's Pilot demonstrates that much of the usage should, in fact, become billable.

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[54] Source documentation for the Winter 2009 report includes the ComEd January 29, 2009 presentation "AMI Pilot Discussion, ComEd Operations.".

[55] Black & Veatch refers to "steady state year" to refer to the first year after the completion of the meter and network deployment. Values in all years are influenced by system growth and escalation assumptions, so no specific year dollar amount remains constant. This first year post deployment, however, is representative of the trend line for subsequent years in the model.

- The Black & Veatch evaluation estimates a higher benefit value of the bad debt reduction. In the previous business case, this benefit was under emphasized due to policy uncertainty with the use of a remote service switch.
- For all of the CIM, UFE, and bad debt benefit opportunities, the benefit values in this evaluation were calculated using a higher price escalation for energy. With the inclusion of these escalation factors, the benefits equate to approximately $151 million annually in steady state year 2017.

Discounted Payback

- The discounted payback was previously estimated at over 16 years. This current evaluation estimates the payback at just over eight years due to a higher estimation in benefits (which more than offset the estimated increase in costs). Also, the prior evaluation utilized a discount rate of 7.1% compared to this evaluation's discount rate of 4.27%.
- The earlier net present value (NPV) was estimated at $28 million (based on a 17-year evaluation period). Given the sizable increase in avoided energy procurement, reduction of bad debt, and increase in energy and delivery service revenues, along with the 20-year evaluation period, this current evaluation estimates the new NPV of net customer impact at $1,296 million.

9.5 Avoided Power Plant Emissions

Black & Veatch has developed a conservative estimation of the potential CO2 equivalent — or *CO2e* [56] — emissions associated with the customer use reductions observed during the pilot project and as projected due to full-scale AMI implementation. Exelon Corporation, the parent company of ComEd, is implementing a business and environmental strategy — Exelon 2020 — to reduce, offset, or displace 15.7 million tons of CO2e by 2020, which includes accounting for customer abatement of emissions due to energy efficiency and demand reduction programs. The estimations provided in this report are developed using a different methodology than Exelon uses for its Greenhouse Gas (GHG) accounting and may not be fully representative of Exelon's internal GHG Inventory Management Plan or Customer Abatement protocol.

Reductions in total energy consumption will result from successful efforts to eliminate theft and tamper conditions. Some additional reduction is also estimated due to voluntary customer reductions attributed to web-based presentment of energy usage information.[57] In all, approximately 380,000 MWh are assumed to be reduced during a typical year once the AMI system is fully installed. To the extent that these reductions reduce power plant cycle times, air emission reductions will result also. When considering the losses associated with the transmission and distribution of energy over long distances, this value of 380,000 can be grossed up by 8.6%[58], yielding a total avoided generation requirement of 415,000 MWh (rounding applied). This compares with ComEd's total of 91.1 million MWh in delivery sales in 2010 (based on 2010 FERC Form 1). 415,000 MWh represents less than 1/200th of ComEd's total energy delivery requirement (when accounting for all types of load and losses).

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[56] CO2e takes into account the contribution of methane and oxides of nitrogen in contributing to global warming. By converting to CO2e, it is possible to create equivalency comparisons to other sources and activities.

[57] ComEd has observed reductions for certain customers participating in the Pilot, and many of these customers have also visited the O-Power website.

[58] FERC Form 1, 2010.

CO2e emissions effects are computed using EPA's eGRID factors for calculating CO2e related to electricity consumption and inversely for any emissions abatement relating to ComEd customer efficiency or demand response programs. For Illinois, which is in eGRID region RFC West, the CO2e emission factor is 1,559.94 lbs/MWh. Applying this factor to the avoided generation of 415,000 MWh/year yields avoided CO2e per year of 650,000,000 pounds avoided CO2e, or ~ 325,000 tons CO2e. The emissions are roughly comparable to the output of a modest sized (750 MW) power plant operating for approximately 10% of its hours based on a 60% duty cycle.

9.6 Avoided Vehicle Emissions

AMI implementation means fewer vehicles travelling to support meter reading and field meter service operations. Based on data from ComEd, an estimated 4.4 million miles of travel would be eliminated each year on average. This represents a net change since there are some increases in vehicle miles of travel within the Field Meter Services due to new types of inspection activities. The reduced Vehicle Miles of Travel (VMT) are principally in passenger and light duty vehicles.

While the reduction is positive, the total emissions reduced are negligible in comparison to the regions total VMT. The emissions are also hard to quantify given the wide range of duty cycles and emission factors for the vehicle fleet. The VMT reduction of approximately 4 million is a very small percentage of the estimated billions of miles of travel by households in the greater Chicago area each year.[59]

[59] See www.transact.org, "Stats by State", the Chicago-Gary-Kenosha metro regional data. The members of each household in the region are estimated to travel 18,000 miles per year on average.

10 Sensitivity Analysis

This ComEd AMI evaluation leverages findings, results, and lessons learned from their on-going AMI Pilot effort. The Pilot has enabled ComEd and Black & Veatch to improve cost and benefit estimates compared with earlier business case analysis efforts, as well as better gauge the level of uncertainly they carry. Any analysis is incomplete without evaluating areas of uncertainty. There are many techniques available to perform such an analysis. In this report Black & Veatch has chosen a straightforward use of the varying the input assumptions to determine output effects.

Listed and described in Table 10.1 are the different data parameters (comprised of both cost and benefit factors) for the purposes of a sensitivity analysis. The approach to the sensitivity analysis is to identify the impact on the base case of independent changes of each of these seven variables, meaning that with each sensitivity analysis performed, only a single parameter is changed. Performing the sensitivity analysis in this manner helps identify the isolated impact on the business case as a result of changing the single variable.

Table 10.1 Summary of Sensitivities and Rationale

Variable	Base Case Value	Sensitivity Analysis Assumption	Description and Rationale
Energy and Delivery Prices[60]	An average 3.7% / year escalation[61]	1.5% annual increase of Energy & Delivery Price (unfavorable)	Future Energy and Delivery services prices ComEd charges its customers have the largest impact on the estimated Benefits since the UFE, CIM, and Bad Debt benefits (avoided costs) are all calculated based on these prices. This change would result in an unfavorable impact to the business case relative to the Base Case.
AMI Meter Price	\$122.78 / meter	\$110 / meter (favorable) \$130 / meter (unfavorable)	The model assumes \$122.78 average price for new AMI smart meters and no escalation during the deployment term. Meter prices are the largest single contributor to capital costs. The meter price may fluctuate; however based on recent ComEd negotiations conducted by ComEd's corporate Supply Chain unit, the unit price uncertainty is low and vendors are willing to lock in the unit price for the duration of the project. Also, smart meter prices have dropped since their introduction, which suggests there is a bias toward more favorable prices with scale and learning effects in manufacturing, and competitive market pressures as the market grows and matures.[62]

[60] 2011-2035 Retail Energy and Delivery Services charges provided by ComEd based on Energy Acquisition data from August 2010. Beyond the three-year price horizon, ComEd relied on the latest U.S. Energy Information Administration (EIA) Annual Energy Outlook for price escalators to estimate long-term energy prices. Avoided capacity costs were taken from PJM's Reliability Pricing Model auction clearing prices for 2011, 2012 and 2013 delivery years; future years were assumed to escalate up to the Cost of New Entry by 2018, at which point it was assumed that capacity prices would track energy prices using the EIA values previously noted. The 2035 - 2040 charges were then forecasted linearly using calculated average escalation of Energy and Delivery Service charges from 2011-2035. The evaluation model then uses a weighted average charge (for Energy and Delivery) based on Residential and C&I forecasted charges.

[61] The model assumes unique year-by-year adjustment. The overall average impact of the yearly variation is approximately equal to an annual escalation rate of 3.7%.

[62] When indifferent to meter type, meter prices have increased during the past ten years, reflecting the advent and introduction of fully functional two-way, disconnect switch equipped and HAN radio equipped smart meter designs.

Variable	Base Case Value	Sensitivity Analysis Assumption	Description and Rationale
UFE (Total Realizable Benefit)	50%	25% (unfavorable) 75% (favorable)	Based on ComEd analysis, the model assumes 0.9% of total distribution system dispatch is UFE, and that 50% of this is reducible with AMI (i.e., can be avoided and therefore estimated as a benefit). The sensitivity analysis performed assesses the impact if 25% or 75% of the UFE is reducible as part of this benefit.
CIM (Percent Billable Consumption)	100% Billable (Energy & Delivery)	0% Billable (100% Energy Purchases Still Avoidable)	In the base case of the evaluation, the assumption is that 100% of the customers who are directly accountable for the current CIM losses (kWh and $) become billable and pay their ComEd bills after AMI is implemented and CIM is eliminated. The sensitivity analysis measures the impact to the business case if all of these customers instead opt to simply not consume the energy they do today. In this case, ComEd still recognizes an avoided power purchase cost, but does not get the benefit out of the delivery services charges.
Reduction of Bad Debt (Remote Connect / Disconnect)	$30.5M	$22M (unfavorable) $45M (favorable)	An estimated $30.5M in Net Bad Debt Expense can be avoided with use of Remote Connect/Disconnect Switch and associated new business practices to manage bad debt. A component of this benefit depends on customer behavior and specifically customer payment and re-connect choices given new knowledge of ComEd's remote switch capabilities. The sensitivity analysis evaluates both a favorable and unfavorable value to this particular estimated benefit.
AMI Meter Installation Cost	$40.48	$30 (favorable) $50 (unfavorable)	The model assumes a unit cost to install of $40.48 per meter based on actual AMI Pilot costs and learnings. The Base Value is based on the pilot learnings. The sensitivities suggest potential cost reductions due to the pilot costs reflecting only cold weather installations, the limited deployment period (reducing the learning curve benefit) and other lessons learned related to elimination of meter installation inefficiencies. An increased installation cost could be realized as a result of significant personnel movement and changes within the installation group causing inefficiencies, increased training costs and other associated overhead.
"Door Knock" Customer Notification Process (on Remote Disconnection for non-pay)	No Knock	Door Knock Required. Cost to achieve = 50% of the estimated Benefit.	Given the current "Part 280" rewrite[63], the disconnection rules are being rewritten to clarify the business process for disconnecting meters for non-payment using technology. ComEd does not know whether an on-premise contact (i.e., "door knock") will be required immediately prior to disconnection. Since the pending new process is uncertain, the additional costs associated with it cannot be estimated. For this reason, the analysis reduces the benefit achievement by 50% as a way to describe potential Part 280 requirements.

Black & Veatch suggests a bias towards lower prices in relation to smart meter designs, not historical average meter prices.

[63] Part 280 refers to a part of the Illinois State Administrative Code, Title 83, Chapter 1, subchapter b. Part 280 governs Service requirements, deposit requirements, payment practices and discontinuance of service practices by utilities falling within state jurisdiction.

10.1 Sensitivity Analysis Results

Table 10.2 presents the impact to the evaluation base case (five-year deployment) in terms of changes to costs, benefits, and overall net customer impact. Understandably, the largest impact to the business case is the achievable benefit of UFE and CIM because of the forecasted energy and delivery escalations over the next 20 years; the UFE and CIM sensitivities did not impact the AMI cost structures. With regard to the cost components, both the AMI meter price and the cost to install are the key variables that may impact overall cost; however, as shown in the numbers below, they have a relatively small impact of approximately $55 million and $45 million, respectively, over the course of the 20-year evaluation period.

Table 10.2 Sensitivity Analysis Results

Business Case Impact	N/A	Unfavorable	Favorable	Unfavorable	Unfavorable	Favorable	Unfavorable
Item	**Base Case (5 year Deployment)**	**A. Energy Price Escalation Factor (1.5% E&D)**	**B. AMI Meter Prices ($110/meter)**	**C. AMI Meter Cost ($130/meter)**	**D. UFE - Achievable Benefit (25% kWh)**	**E. UFE - Achievable Benefit (75% kWh)**	**F. CIM - % Billable (0%)**
Costs (Cumulative 20 years)							
O&M Expense for Smart Meter System	$665.3	$665.3	$665.3	$665.3	$665.3	$665.3	$665.3
New Capital Investment for Smart Meter System	$995.8	$995.8	$941.5	$1,026.4	$995.8	$995.8	$995.8
Sub-Total	***$1,661***	***$1,661***	***$1,607***	***$1,692***	***$1,661***	***$ 1,661***	***$1,661***
Operational Benefits & Delivery Service Revenues (Cumulative 20 years)							
Operational Efficiencies and Cost Reductions	$1,625.2	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,630.4
Avoidance of Capital Expenditures	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4
Delivery Service Revenues – UFE and CIM	$564.2	$414.5	$564.2	$564.2	$516.7	$611.7	$95.0
Sub-Total	***$2,192***	***$2,048***	***$2,198***	***$2,198***	***$2,151***	***$2,246***	***$1,729***
Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cumulative 20 yrs)							
Reduction in Purchased Power - UFE and CIM	$707.5	$563.2	$707.5	$707.5	$353.8	$1,061.3	$1,581.6
Energy and Other Revenues - UFE and CIM	$1,051.0	$836.7	$1,051.0	$1,051.0	$962.5	$1,139.4	$176.9
Reduction in Bad Debt Expenses	$790.7	$612.4	$790.7	$790.7	$790.7	$790.7	$790.7
Sub-Total	***$2,549***	***$2,012***	***$2,550***	***$2,550***	***$2,107***	***$2,991***	***$2,550***
Total / Net (Cumulative 20 years)							
Net Total (Benefits Less Costs)	***$3,081***	***$2,400***	***$3,140***	***$3,056***	***$2,596***	***$3,576***	***$2,617***
Net Present Value (NPV)	***$1,296***	***$930***	***$1,360***	***$1,264***	***$1,014***	***$1,583***	***$1,026***
Discounted Payback (Yrs)	**8**	**9**	**8**	**9**	**9**	**8**	**9**

*All $ values in Millions. * NPV calculated based on discount rate = 4.27%*

Table 10.3 Sensitivity Analysis Results (Continued)

Business Case Impact	N/A	Unfavorable	Favorable	Unfavorable	Favorable	Unfavorable	N/A
Item	**Base Case (5 year Deployment)**	**G. AMI Meter Install Cost - $50/install**	**H. AMI Meter Installation Cost ($30/install)**	**I. Bad Debt Expense ($22M)**	**J. Bad Debt Expense ($45M)**	**K. Door Knock Disconnect (50% of Benefit)**	**L. Base Case (10 year Deployment)**
Costs (Cumulative 20 years)							
O&M Expense for Smart Meter System	$665.3	$665.3	$665.3	$665.3	$665.3	$1,055.7	$652.6
New Capital Investment for Smart Meter System	$995.8	$1,037.1	$950.3	$995.8	$995.8	$995.8	$1,030.6
Sub-Total	***$1,661***	***$1,702***	***$1,616***	***$1,661***	***$1,661***	***$2,052***	***$1,683***
Operational Benefits & Delivery Service Revenues (Cumulative 20 years)							
Operational Efficiencies and Cost Reductions	$1,625.2	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,539.4
Avoidance of Capital Expenditures	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4
Delivery Service Revenues – UFE and CIM	$564.2	$564.2	$564.2	$564.2	$564.2	$564.2	$531.3
Sub-Total	***$2,192***	***$2,198***	***$2,198***	***$2,198***	***$2,198***	***$2,198***	***$2,074***
Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cumulative 20 yrs)							
Reduction in Purchased Power Costs - UFE and CIM	$707.5	$707.5	$707.5	$707.5	$707.5	$707.5	$667.1
Energy and Other Revenues - UFE and CIM	$1,051.0	$1,051.0	$1,051.0	$1,051.0	$1,051.0	$1,051.0	$991.3
Reduction in Bad Debt Expenses	$790.7	$790.7	$790.7	$569.6	$1,165.1	$790.7	$745.1
Sub-Total	***$2,549***	***$2,549***	***$2,549***	***$2,328***	***$2,924***	***$2,549***	***$2,403***
Total / Net (Cumulative 20 years)							
Net Total (Benefits Less Costs)	***$3,081***	***$3,045***	***$3,132***	***$2,865***	***$3,461***	***$2,696***	***$2,795***
Net Present Value (NPV)	***$1,296***	***$1,252***	***$1,350***	***$1,170***	***$1,516***	***$1,069***	***$1,152***
Discounted Payback (Yrs)	**8**	**8**	**8**	**9**	**8**	**9**	**9**

*All $ values in Millions. * NPV calculated based on discount rate = 4.27%*

10.2 Isolating the Impact of the Disconnect Switch

The ISSGC report recommends, "To the extent that it is feasible to separate underlying platforms from individual applications, smart grid applications contained within a package should still be subject to individual cost-benefit analysis based on their stand-alone incremental costs and benefits."[64]

It is feasible for ComEd to source advanced meters without the disconnect switch capability. Moreover, this capability helps drive specific operational changes. ComEd could meet prospectively many of its demand response program needs without deploying the disconnect switch, and for this reason some stakeholders may want to view the switch as an incremental investment.

[64] ISSGC Report, page 250.

ComEd estimates that the connect/disconnect switch feature adds approximately $35 to the cost of each AMI meter. This feature is available for a percentage, but not all, of ComEd's meters due to physical constraints on the meters (e.g., three-phase vs. single-phase). Estimating that 92% of ComEd's AMI meters would have this switch capability, ComEd would invest approximately $130 million[65] in meter capital for this feature, or ~ 15% of total capital expenditures over 20 years. However, this switch feature would largely enable and drive benefits associated with bad debt ($791 million), and CIM ($1,343 million). Therefore, the isolated benefit-cost relationship of the disconnect switch is overwhelmingly positive.

[65] These costs are included and considered within the overall AMI evaluation.

11 High Rise Proof of Concept

The driver in separating the different meter segments or populations (i.e., the High Rise and Rural geographic areas) is due to the fact that there are varying AMI infrastructure requirements and thus a different cost structure for each. For the High Rise segment, higher cost estimates were included in the evaluation to account for uncertainty that some of the AMI meters in the High Rise segment cannot achieve and/or maintain connectivity to the AMI "mesh" network. While ComEd's data from the High Rise proof of concept shows favorable connectivity and read success, only one month's performance (one successful billing read per month) was validated. Moreover, the selected buildings are not the most challenging high rise buildings with respects to RF connectivity.

The business case evaluation assumes that the same RF network AMI technology can effectively support each of these segments; however, it is also assumes that an increased number of AMI components—specifically Access Points (APs), repeaters, and/or external antennas—will be required in these areas to achieve and support ongoing AMI telecommunications.

The following cost inputs and assumptions were included in the evaluation to estimate AMI costs:

- 100,000 High Rise meters—100% are supported by the same AMI network that is assumed to be deployed across the rest of ComEd's meters.
- 4,083 meters in High Rise area will require external antennae—This figure was calculated based on Pilot lessons learned and then extrapolated across the High Rise population.
- $500 per meter to install external antennas—This reasonable cost estimate was provided by a ComEd vendor.
- 431 buildings in High Rise area will require an Access Point on each building.
- $300/building for monthly AP maintenance fee is assumed.

It is also important to remember that the deployment plan used in the evaluation calls for AMI deployment to both the High Rise and Rural meter segments during the last year (12 months) of the 5- and 10-year deployment cases, 2016 and 2020 respectively. Given the maturity rate of AMI technologies, it is not unrealistic to assume that either the next generation of AMI technologies (at a similar or less expensive price point) will be available at the time of deployment to meet the High Rise segment performance requirements. Black & Veatch recommends ComEd re-assess its AMI deployment strategy for its High Rise and Rural meter segments prior to deploying either its AMI meters and/or any support AMI network infrastructure (i.e., Access Points or Repeaters).

12 Comparison with Other Utility AMI Business Cases

12.1 Introduction

This section provides a high-level summary of the results presented in this evaluation to a small sample of four other utility business cases, using information from the public domain. While this does not represent a statistically adequate sample size, the comparisons help illustrate the range of values that a few other utilities have estimated for their business cases. Additionally, any comparison is challenged by the fact that the policy, business, system, system scale, customer stakeholder requirements, and analysis methods and assumptions are typically unique. Each utility starts from a different cost basis and has differing challenges and program goals. Consequently, it is difficult to align costs and benefits. Examples of this uniqueness include:

- Electric and gas requirements vs. electric only; allocation cost methods.
- Inclusion or exclusion of distribution asset-related benefits.
- Inclusion or exclusion of demand response programs, costs and benefits.
- Inclusion or exclusion of private backhaul communication system improvements, such as high speed fiber and radio communications in various “tiers”.
- Urban vs. suburban vs. rural density characteristics.
- System size.
- Starting point in terms of meter reading automation. (Is the current system to be replaced a manual system? A drive by system, etc.).
- Scope of benefits; nature and degree of challenges related to benefit classifications (e.g., theft, tamper, other forms of UFE, consumption on inactive accounts, bad debt).
- Unique regulatory requirements around customer notification in disconnect and reconnect situations.
- Unique regulatory requirements regarding the technical specifications and performance characteristics.
- Unique internal system requirements. For example, unique billing system requirements, including unique upgrade and interface requirements.
- Unique requirements around measurement and verification requirements.
- Unique market conditions, (e.g., relationship to third party retail energy providers, and potential) requirements around data protection, provision, and meter data access.
- Synergies or lack thereof with parent company and operating regions; jurisdictional costs or opportunities when operating regions are located in multiple state jurisdictions.
- Costs associated with legacy systems and potential asset retirements.
- Conventions used to structure cost/benefit work. (Time periods, escalation factors).
- System growth differences.
- Labor cost differentials.

These and other factors that drive uniqueness should be considered in any side-by-side review of costs, benefits or overall business case results. The values discussed in this section have been rounded and approximate for convenience.

12.2 BC Hydro[66]

BC Hydro is an electric utility and plans to install ~ 1.8 million smart meters over 20 years. BC Hydro estimates $359 million in operational efficiencies and avoided capital, or $199/meter. These are figures are expressed on a net present value basis. Care is needed in making strict comparisons with figures presented on a nominal dollar basis. The BC Hydro nominal figures (unavailable in report) are likely 1.5 to 2 times higher assuming various terms and discount rates. ComEd business case assumes approximately $400/meter, nominal dollars basis, which is roughly comparable to the BC Hydro results on a nominal dollars basis.

BC Hydro further estimates $940 million in energy savings, or $522/meter (net present value basis) compared to ComEd business case around $640/meter of energy-related savings and bad debt reductions (nominal dollar basis). Due to differences in scope alignment, BC Hydro's additional benefits related to demand response and conservation programs are not included in these figures. These additional benefits would best align with ComEd's demand response program.[67]

BC Hydro's theft detection-related benefit is $407/meter (net present value basis). This is included in the above figures. This compares to the ComEd business case of $245/meter (nominal), which includes other sources of losses within a broader category of unaccounted for energy (UFE). The ComEd business case value accounts for reductions in theft in terms of avoided power purchase costs and the effects of increased revenues when customers' behavior is altered. It is not clear how this aligns with BC Hydro's benefit assumptions.

BC Hydro identifies costs associated with program development of ~ $27/meter (Initiation, Identification, and Definition phases). Compare to ComEd's pilot costs of ~ $17/meter (when amortized over all ComEd's meters). The ComEd Pilot costs are considered sunk and are out of scope of the evaluation.

BC Hydro implementation costs are ~ $341/meter (NPV basis). For purposes of comparison, this figure excludes costs for certain items not well aligned to the ComEd AMI program scope.[68] Compare this to ComEd's implementation period costs of ~ $260/meter (nominal). A comparison for on-going operations costs is not readily apparent. ComEd's operational costs are ~ $10/meter/year in steady state years.

12.3 PECO

PECO plans on installing a smart meter system covering 600,000 electric customers. Initial program costs are estimated at $290 million, or $483/meter. If including the $45 million in stranded cost recovery, the cost is $558/meter. DOE grant funding reduces these estimates. Also, these costs provide for coverage of PECO's entire service territory, per Act 129 requirements, and provide low marginal costs of incremental smart

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[66] Smart Metering & Infrastructure Program Business Case, BC Hydro. March 2011.

[67] Ibid.

[68] Table 2, Page 10. Smart Metering & Infrastructure Program Business Case, BC Hydro. March, 2011. For this comparison, $316 million is omitted from the $930 million total, in areas of conservation tools, grid modernization infrastructure upgrades, contingency and reserve.

meter installations beyond the initial 600,000.[69] These values compare with ComEd's business case of $260/meter. A comparison for on-going operations costs is not apparent. PECO's three-year operational costs are identified for its implementation period as $27/meter. Whether this is indicative of future year operating costs is unknown. ComEd's operational costs are ~ $10/meter/year in steady state years.

A comparison of benefits is not germane. PECO is mandated to install smart meters per the requirements of Act 129, an Act of the Pennsylvania legislature. Smart meters are deemed necessary to support the energy efficiency goals of Act 129, which are extensive, but not aligned with the ComEd business case here. (A comparison to ComEd's demand response program would be more appropriate). Furthermore, PECO installed a first generation automated metering system about 10 years ago, and has already reduced certain operational benefits, such as meter reading. The PECO business case includes provisions for some additional benefits related to automated disconnects.

12.4 SCE

Southern California Edison (SCE) is deploying 5.3 million smart meters over five years as part of an AMI and DR system. SCE estimates $4.6 billion in operational efficiencies and avoided capital, or $863/meter (compare to ComEd business case of $400/meter).[70,71] These values exclude additional value SCE estimates from demand response programs, as well as from identification of theft conditions. The SCE demand response benefits would best align with ComEd's demand response program. While there are differences in benefit scope the two business cases are aligned to operational benefits. The SCE business case, for example, includes improvements in the meter-to-cash cycle. It excludes, however, theft-related benefits.

SCE identifies costs associated with program development of ~ $9/meter (Phase II costs, pre-deployment). Compare to ComEd's pilot costs of ~ $17/meter (when amortized over all ComEd's meters). The ComEd Pilot costs are considered sunk and are out of scope of the evaluation.

SCE implementation period costs are ~ $275/meter.[72] Compare this to ComEd's implementation period costs of $260/meter. A comparison for on-going operations costs is imprecise. ComEd's operational costs are ~ $10/meter/year in steady state years. SCE's on-going costs are ~ $7/meter/year in steady state.

The SCE values are 2006 values. Escalation adjustment increases these figures by ~ 10%, assuming a 2% level of increase per year.

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[69] See Exhibit AKP-1, in PECO's PUC testimony for Act 129 Smart Meter Plan for implementation approval, http://www.puc.state.pa.us/pcdocs/1050889.pdf

[70] See Edison SmartConnectTM Deployment Funding and Cost Recovery, Volume 2: Deployment Plan. Before the PUC of the State of California. Table II-1, page 13. Available at http://sites.energetics.com/MADRI/toolbox/pdfs/business_cases/sce_vol2_deployment.pdf. The costs and benefit values also require some adjustment for escalation, which is unaccounted for in the above figures.

[71] The basis of $406/meter is summation of the ComEd 20 year benefit for avoided annual recurring operations costs and avoided capital expenditures, divided by 4 million meters.

[72] Table 11-1 deployment costs, less costs for contingency and customer tariffs, programs and services.

12.5 PHI Delmarva Delaware (DE)

PHI Delmarva is an electric and gas utility (303,000 and 125,000 electric and gas meters respectively.[73] Total implementation costs for electric are ~ $74 million, or $244/meter (compare to ComEd business case of approximately $260/meter). On-going costs for Delmarva DE are estimated at ~ $2/meter, compared to ~ $10 at ComEd. For the Delmarva DE business case, approximately 80% of program costs are returned with operational efficiency and cost avoidance benefits. Additional benefits related to demand response increase the program value.

[73] Advanced Metering Business Case Including Demand-Side Management Benefits, DE Docket 07-28, September 7, 2007.

13 Other Potential Benefits

13.1 Transformer Load Management

Improved management of distribution service transformers resulting from the analysis of AMI data can translate into reduced unanticipated transformer failures and the associated costs and customer impact to such outages. The AMI system will provide interval usage data on all customers and if the ComEd GIS application can properly associate the customers to their specific distribution service transformer, then by providing the known rating of the transformer and comparing with the aggregate loading; ComEd can identify the likely overloaded transformers.

Prior identification of transformers that are at risk for failure allows these transformers to be analyzed and if required, to be replaced on regular maintenance work. The current business processes likely have no way to know that a transformer is potentially overloaded unless the customer calls with voltage or power quality problems (indicative of a transformer beginning the failure process). Otherwise, the transformer runs to failure and ComEd replaces as an emergency work order, along with the oil cleanup, pole or manhole fire, etc. that can come with transformer failures.

The savings would be based on the difference between replacing the transformers in a planned manner on straight time or replacing the transformers during an outage, potentially on overtime. Also there may be a savings to re-deploying transformers that are still useful, rather than waiting for them to fail. Finally, there is an environmental impact in that a transformer that fails is likely to spill oil, or possibly start a fire and that would be avoided with a planned replacement. There are also customer service improvements because a planned transformer replacement will likely result in a shorter outage than one done on emergency.

13.2 Reduced Truck Rolls Due to Customer Equipment Problems

In addition to the "avoided Single Lights Out" benefit associated with customers that had already been restored on prior work tickets, there are the reduced truck rolls associated with ComEd dispatching service personnel for power outage events that are caused by customer equipment problems. Currently, ComEd has no reliable and consistent method of determining the validity nor cause of customer reported outage single customer out conditions. The AMI system provides the ability to query the electric meter in near real-time to determine if the meter has power.

When a customer contacts ComEd with an outage complaint, the ComEd Call Center Representative can initiate an on-request query of the meter. In the event that the meter reports power availability, it can be assumed that the problem is with the customer equipment—blown fuses or tripped circuit breaker, and the CSR can direct the customer to check these conditions, often rectifying the problem without requiring the dispatch of ComEd service personnel. This business process contributes to the benefit, but the majority of the benefit is expected to occur on the dispatching process of managing outages by allowing the dispatcher similar functionality to validate the outage condition before dispatching a vehicle to the location. The potential savings associated with this benefit are the cost savings due to reduced truck rolls.

13.3 Historical Outage Information

The AMI systems provide both near real-time and historical outage information from the electric meters. The meters collect sustained and momentary outage information which is more detailed than traditionally available. The meter tracks the number of outages experienced at a particular customer location along with the time of the incident and the length of the outage. This historical outage information can be used by ComEd to supplement other sources of information such as SCADA and customer reported outages regarding the condition and operation of the distribution system.

ComEd may be able to use the momentary information from AMI systems to identify feeders and line sections that have large numbers of momentary outages. Auto reclosing equipment such as circuit re-closers track the operation count, but it is often difficult to correlate these counts to number of actual events and problems. By collecting detailed momentary outage data on a select number of meters, ComEd could identify the actual number of events and pinpoint locations where there is a lot of activity. The outages could be due to animals or other causes, but if they occur during storms or high wind conditions, they are likely tree related.

The benefit associated with this is the potential improved effectiveness of reliability program expenditures.

14 Non-Operational Benefits of AMI and Smart Grid Options

The evaluation report includes quantification of benefit impacts arising from the “operational” use of the AMI system. The Results section discusses these impacts and their potential financial value to ComEd and its customers.

There are additional benefits, which ComEd can anticipate, with important qualification. First, there are the benefits of aggregate energy consumption reductions for residential customers for the AMI Pilot customers (excluding CAP customers) that have altered their electricity use due to education, awareness, and the use of advanced meters.[74] This includes a summary of PJM billing determinant categories and distribution system cost reductions. These benefits are not captured in the financial results presented in Section 10 (Results). Likewise, it is possible that there additional impacts, broadly considered, to all market participants if the level of usage by ComEd’s customers declines, per the UFE and CIM benefits.

14.1 Benefits of Reduced Consumption

The ComEd 4.0 million AMI meter deployment (5-year plan) is based on a four (4) year and three (3) month schedule that starts in the fall of 2012 and is completed at the end of 2016. Straight-line meter deployment is assumed over the period of implementation. Table 14.1 provides a summary of the energy reductions, in terms of GWh, expected under base, low, and high case scenarios.

The benefits from Consumption on Inactive meters (CIM) are estimated to be 0 in the base case and 440 GWh in the high case. Energy efficiency improvements[75], due to the availability of web-based customer usage information, are assumed to be 30 GWh per year for the base-case scenario. A one year lag is assumed to achieve full UFE reduction benefits. Starting in the second quarter of 2017 the base scenario for UFE reductions assumes a reduction of 350 GWh.

The total reduction from the three categories is 380 GWh for the base scenario (0.4% of total 2017 energy consumption[76]) and 1,010 GWh for the high case scenario (1.0% of total 2017 energy consumption).

[74] The total consumption changes for this sample residential population (approximately 119,000 less CAP participants) was determined by ComEd as the difference in the energy consumption from the AMI Pilot against a baseline period, prior to the Pilot.

[75] The Energy efficiency improvements are those consumption reductions by customer that have altered their electricity use due to education, awareness, and the use of advanced meters

[76] 2017 energy consumption estimated based on 95,000 GWh of Retail load in 2009, and then escalated by 0.5% annually.

Table 14.1 Base and Sensitivity Cases for GWh Reductions

GWh Reduction Categories	Base Scenario	Sensitivity Analysis	
	GWh	Low	High
Energy Efficiency Improvements	30	30	30
Consumption on Inactive (CIM)	0	0	440
Unaccounted for Energy (UFE)	350	180	540
TOTAL	**380**	**210**	**1,010**

The benefits from these reductions can be defined in monetary terms as a function of a number of benefit categories. First, there are the effects of reductions in the amount of capacity services ComEd will need to procure. Average capacity reductions can be ascribed based on the assumption that these reductions occur uniformly over 8,760 hours per year. Making certain assumptions about the allocation of the energy use decline over certain hours of the day, month and year, the total energy use decline (base case) may drive a decline in ComEd's capacity need of about 43 MW over each successive year after the second quarter of 2017.[77]

This ComEd MW reduction—which, except for the Energy Efficiency related effect, is reflected implicitly in the decrease in power purchase costs monetized in the Results section—can be ***decomposed*** to a 43 MW reduction in the following:

- Required RPM capacity obligation purchase
- Required transmission capacity (in PJM's transmission services process).[78]
- Resource Adequacy (non-binding).

Additionally, the volume of energy reduced in the base case is estimated to be 380 GWh/yr, which suggests a set of PJM energy (volumetric) related benefits from reduced charges, such as the following:

- Monthly transmission use operating charges[79] (MWh).
- Spot Market Energy charges (the sum of the PJM Member's hourly day-ahead and balancing spot market energy charges (+/-) based on the member's billing account net hourly spot market interchange).
- Transmission Losses charges (the sum of the PJM Member's or Transmission. Customer's hourly day-ahead and balancing loss charges (+/-) for all hours.
- Meter Error Correction charges (the sum of the PJM Member's charge adjustments (+/-) resulting from correction of meter errors).
- PJM Scheduling, System Control and Dispatch Service charges (each PJM Member's monthly share of PJM's monthly operating expenses).
- FERC, NERC, and Reliability First Corporation charges.

[77] The calculation is 380,000 MWh/8760 hours = 43.38 MW per year.

[78] One of these charges is the Network Integration Transmission Service charge, the transmission customer's monthly transmission demand charge. It is based on applicable transmission zone rates. See, PJM Manual 29.

[79] See, PJM Manual 33, Administrative Services, at http://pjm.com/~/media/documents/manuals/m33.ashx.

- Frequency regulation charges (the sum of hourly regulation charges for all hours that ComEd or third parties purchased regulation).

There are also a number of other PJM charges that may be reduced as a result of reductions in capacity and energy need, though a number of these may be difficult to quantify.[80],[81]

14.2 Market Benefits

The business case assumes impacts to consumption and as described in section 14.1, these impacts can be viewed in terms of underlying resource cost categories in the two general areas of capacity and energy services.

To the extent that the consumption of energy drives total decreases in the need for energy and capacity (as quantified in Table 13.1), these decreases may also influence market prices. The effects of any potential market prices are deemed to be small, however, due to the aggregate amount of decline in aggregate energy and capacity services required. The 43 MW reduction in capacity, for example, represents a small fraction of PJM's total system capacity requirement of around 150,000 MW (less than 0.03%).

Secondly, 380 GWh per year of reduced energy use represents the energy consumed in approximately 30,000 homes, assuming 1,000 kWh per home in energy consumption each month. This is a relatively small result in terms of the total regional energy market (e.g., wholesale generators for example selling energy services as distinct from capacity services), and the potential influence on prices in this market is neglible.

Thirdly, the potential for either the 43 MW of capacity services or the 380,000 MWh of reduced energy consumption to influence the nature of congestion impacts (and associated transmission-access charges) is most likely insignificant, given the scope of these effects.

14.3 Additional Qualitative Benefits

The efforts to reduce consumption, as described above, sit in a context of a variety of potential demand-side programs and initiatives. These include:

- Home energy portal—The website as currently defined plus the additional efforts to education customers about their energy use.

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[80] See especially, PJM Manual 29 and the related calculations.

[81] There are a few cautions that should be observed when interpreting these results. Energy Efficiency improvements are a general measure of consumer response to customer prices and information about electricity use. Persistence is in this case difficult to ascertain. Some have suggested that in the longer-term the benefits of general information are likely to decrease. Others argue that as consumers become more informed, reductions in consumption will become larger. Decreased consumption reductions may result from lack of sustained consumer attention to the benefits of demand reduction. In short, the consumer reaction to electricity prices dims and becomes less important as the perceived benefits "wear off." The opposite effect is when customers become more engaged and more capable of achieving consumption reduction benefits. With better consumer information and pricing more distinct retail pricing will increase the amount of consumption that is reduced—a result to be expected for some customers. Finally, it is recommended that ComEd include the Energy Efficiency impact in its overall demand response program and associated analysis and consider it an additional effect of the demand response initiative.

- Thermostat Control—Services (options) to alter heating/cooling set point and appliance performance.
- Additional UFE, including energy system losses that cannot be attributable to specific causes.[82]
- Real Time Pricing (RTP)—Passing system pricing to customers so that they can directly respond, including response to Critical Peak Pricing (CPP).

The specific benefits that will result from these reductions and efficiency improvements can be summarized in the following set of categories:

- Reduced energy needs and reduced Locational Marginal Prices (LMPs)
- Reduced Emergency Capacity (RPM) needs and prices
- Reduced ancillary service requirements (Operating Reserves, Frequency Regulation, Volt/VAR requirements, and Black-start)
- Demand-response provision (in a set of PJM markets)
- Energy Efficiency provision
- Reduced PJM administrative charges
- Increased customer value-of-service
- Reduced distribution service costs
- Option value that results from capture of multiple high-priced value streams

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[82] UFE is considered to be "unaccounted for energy" because it is indeed difficult to account for it, and related losses are difficult to attribute to specific causes. The UFE benefit is described in Section 8 (Benefits). Interval meters are more accurate, and when coupled with remote connect/disconnect the result is to substantially reduce the metering error and thus the UFE. Moreover, AMI metering and its greater accuracy allow for more accurate summation of the amount of energy delivered to the distribution system, as compared to the transmission system. This allows for more accurate in the determination of transmission losses and related transmission UFE as compared to distribution related UFE.

15 Black & Veatch Observations and Recommendations

15.1 Benefit Area—UFE, CIM, and Bad Debt

ComEd's distribution losses and unbilled meters exceed the industry average. ComEd also has relatively high levels of bad debt. AMI allows, reasonably so in Black & Veatch's opinion, to offer opportunities for ComEd to significantly reduce the losses that these circumstances generate. In the area of UFE, Black & Veatch did not have access to descriptions of specific business practices that ComEd might adopt to address UFE and that are uniquely tied to automation. Black & Veatch recognizes that UFE conditions are an important element of AMI, and that AMI provides additional visibility and potential tools by which to identify sources of losses; Black & Veatch recommends that ComEd continue during the next 16 months (prior to the start of full deployment) to design the specific business processes and business process changes in the areas of Revenue Management and Revenue Protection that will allow the organization equipped with AMI-related tools and capabilities to address these areas of operational inefficiency. Pilot data was not presented that validated the UFE opportunity.

With regards to the estimated CIM benefits, the base case assumes that 100% of the target losses (currently prior to AMI) will translate into billable consumption that is paid by customers, as opposed to a reduction in consumption relative to current levels. This assumption of 100% of the benefit turning into billable (and paid-for) consumption may be unachievable, and as such, sensitivity analysis was performed to understand the impact to the evaluation if some of this benefit comes in the form of reduced consumption.

15.2 Cost to Achieve—Disconnect Process

For use of the disconnect switch, resolution of ComEd's notice requirements to customers (e.g., "door knock") is a current uncertainty that may impact the business case results. Both the cost to achieve and the benefits (should they lag due to additional process steps) may be impacted depending on regulatory requirements in this area.

15.3 Field Installation Work and Deployment Strategies

Black & Veatch recommends continued planning on the work scope and attendant requirements (facilities, IT support, meter provisioning, etc.) associated with field installation. This is an area of considerable complexity especially when considering the magnitude of ComEd's meter deployment.

Black & Veatch encourages ComEd to continue field deployment strategies that might optimize costs and benefits recognition. By targeting high meter cost areas and high benefit areas ComEd may be able to improve the business case.

Black & Veatch encourages ComEd to continue planning around ComEd's plan to transition personnel from current meter activities to meter field installation and cross-dock activities. This promises to be an important benefit to ComEd's meter readers otherwise affected by automation. Imparting new skills and allowing for retention is a laudable goal and planning will better define how to make this realizable. (Black & Veatch believes the business case evaluation is consistent with these assumptions).

15.4 Contracts

Black & Veatch encourages ComEd to carefully consider the adequacy of its supply contracts for smart meter equipment and services to the extent that these contracts may not have anticipated a full-scale system implementation requirement. The long-term implications of the proposed AMI head end "outsourcing" should be fully considered in light of long-term operational requirements, capabilities and likely costs and benefits.

Supply chain requirements may drive schedule to the extent that this work does not proceed soon. Delays in putting in place contracts for full deployment will impact the business case assumptions related to the feasibility of a 2012 start date.

15.5 Technical Performance Specification

Black & Veatch has endeavored to be disciplined in conducting the evaluation, in particular noting ISSGC scope delineation considerations (e.g., Application domains) and associated benefit scope, and the baseline of information already developed regarding the technical performance characteristics and specifications of the proposed systems. ComEd should review the ISSGC requirements and recommendations, compare this to the existing base of information, and determine gaps, if any.

15.6 Business Requirements and Processes

Additionally, Black & Veatch has not reviewed the adequacy of ComEd's current business "state" documentation (meaning current and future states of all impacted systems), the change required in its systems (systems, integrations, hiring, training, organizational structures, etc.). Nor has overall business readiness been assessed as ComEd proceeds forward in its AMI design, planning and implementation work associated with full scale roll out. ComEd's ability to plan effectively, and to create the organizational structure around the initiative, is key to ComEd's ability to meet the 2012 schedule and the benefit realizations estimated in this evaluation.

Black & Veatch also recommends providing additional planning details regarding the design, planning and organizational change work required to be ready to implement the full-scale AMI system. Black & Veatch offers that the challenges of deploying 131,000 meters will increase with scale. Much will depend on the sufficiency of planning, the resourcefulness of personnel, and the quality of contracts and relationships with key vendors. Left unaddressed, these considerations remain risk factors.

15.7 Future AMI Opportunities

Black & Veatch has focused its inquiry into the review of ComEd's "operational" business case largely based on the goals to achieve narrow and specific operational changes and improvements. In Black & Veatch's view, this is a strength of the ComEd approach in directing this evaluation. By focusing on the core investment related to AMI, ComEd will be able to clearly isolate the additional costs and benefit opportunities of extending the AMI infrastructure's capabilities to achieve greater results. At the same time, ComEd is encouraged to focus attention on potential likely future applications and what requirements are needed from the AMI systems to support these requirements. (This evaluation, for example, has not addressed power quality benefit opportunities, and opportunities to better manage distribution system assets. AMI contributes to these benefits).

Black & Veatch recommends that ComEd supplement its business planning to address areas of recommendations made in the ISSGC report that fall outside of the purview of this review. Examples include attention to certain policy issues such as security, interoperability, and customer privacy. The smart meter workshops covered some of these issues.

15.8 Adequacy of Business Readiness

It is in part because of the extensive work ComEd has already accomplished (as described in the quarterly reports) that Black & Veatch believes it is reasonable to assume that a continuation of AMI smart meter deployments beginning in late 2012 is feasible. This is an important business case assumption included in the evaluation, which assumes full scale deployment starting in Q4, 2012.

This does not mean that there is not critical business readiness work to prepare the organization prior to this date. An example is the preparation of detailed work scopes for potential inclusion in vendor contracts. Black & Veatch, however, has neither been party to nor has it independently validated any such detailed work plans associated with this business readiness work to be conducted over the next 18 months. Nonetheless, Black & Veatch does not find incongruence in the scope and timing of benefits realization described in the evaluation and the plausibility of beginning “mass” meter deployment in approximately 16 months. The reasons are as follows:

- Because of the extensive work ComEd has conducted to date in support of the Pilot, core integrations—such AMI system to MDM to Billing—are completed in support of basic monthly billing and meter read validation and editing requirements.
- The evaluation assumes a narrow focus on “operational” benefits and ComEd is already in the process of designing new information and system requirements to support these benefits and is using the Pilot system to perform certain meter operations in support of these benefits.
- The evaluation adjusts the benefit realization to account for lag times associated with meter/system availability, system integration requirements, process redesign and change management activities.
- The business case analysis is not dependent on the automation of certain meter solutions in specific environments, except in the case of rural and high rise environments. Rather, the deployment model is based on simple assumptions without regard to geography, metering solution, or high-cost-to-serve areas. This leaves “head room” for detailed deployment planning to improve program performance.
- Challenging RF communication environments, such as the high-rise building environments, are timed in the evaluation’s analysis to occur at the end of the deployment period. Coupled with conservative infrastructure assumptions, this allows for deployment and operating experience and the evolution of system capabilities to reduce the risk of metering performance in these areas.

Black & Veatch identifies the importance of the next 12 to 16 months to ComEd in developing its operational deployments plans, recognizing the significant challenges that may arise as it scales up network deployment, meter installation, IT systems and business processes to align to a five year, four million meter deployment time table.

15.9 Impact of the AMI Implementation on ComEd's Existing Assets

The AMI implementation will require the removal and premature retirement of nearly all of ComEd's current meters over the AMI meter deployment term (5 or 10 year deployment periods). Currently, there is a mix of electro-mechanical meters and more advanced solid-state meters, which are providing demand measurement to commercial accounts. The meter fleet is also composed of different kinds of metering communication solutions. At present, there are approximately 6,080 ComEd meters on automatic read systems. These meters will similarly be retired as part of the AMI implementation.

This evaluation accounts for the cost effects that the AMI Implementation will have on these current, non-AMI meters. For purposes of this evaluation, the ComEd Finance team performed financial analysis, and provided to the Black & Veatch team, annual costs based on the assumption that the remaining un-recovered investment in these assets would be recovered on an accelerated depreciation schedule consistent with the AMI meter deployment schedule – i.e. accelerated recovery over the 5 or 10 year deployment schedules.

At the present time, ComEd has meter investment totaling $367.2 million with an associated depreciation reserve of $146.3 million. Thus, the unrecovered cost at the present time amounts to $220.9 million (367.2 less 146.3). Accumulated deferred income taxes associated with this investment amounts to $43.7 million. Thus, rate base associated with existing meter investment amounts to $177.2 million (220.9 less 43.7). Assuming a 5-year deployment, the net present value of the revenue requirements associated with the impact of the accelerated recovery of the existing meters amounts to $6.1 million using a 4.27 percent discount factor (20-year Treasury note). Assuming a 10-year deployment, the net present value of the revenue requirements associated with the impact of the accelerated recovery of the existing meters amounts to $4.5 million using a 4.27 percent discount factor (20-year Treasury note).

Policy makers recognize the importance of this matter on program impacts. FERC, for example, has issued preliminary guidance (March, 2009) indicating support for the recovery of these otherwise "stranded" investments. Regardless, this requires further attention by ComEd and its Stakeholders to properly and thoroughly address.

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Appendix A: AMI Pilot Lessons

The evaluation has involved detailed discussions with many ComEd managers in order to understand operational cost structures and benefits (either achieved or foregone) under the "As Is" (no AMI implementation) and the "To Be" (with AMI) scenarios. The cost and benefit projections are based on an understanding of the specific kinds of work for which each department will be responsible given the availability of the AMI system and related tools, and assumptions about new work processes. For each affected area, work volumes were estimated, and costs were built off of these work volume level assumptions. This discovery involved both recognition of avoided costs due to work that would no longer be conducted, and new costs due to new responsibilities.

As part of this effort, each manager shared expectations about how the AMI system would impact their respective work areas. These expectations, and the resulting data, have been further influenced by the specific learning experiences ComEd has gone through in designing, building and operating the AMI Pilot system. The Pilot experience has helped ComEd design business requirements spanning the design, build-out, and on-going operations of an integrated AMI system. By informing managers about the potential impacts of AMI, the Pilot lessons help shape the results of this evaluation. ComEd believes that continued operation of the Pilot will continue to provide information and lessons that will be leveraged for future expansion plans.

The lessons are summarized in this section of the report and organized by the following categories:

- Systems design, planning, and implementation
- Operations
- Customer experience

A.1 Systems Designs, Planning, and Implementation

Network and Meter Deployment

ComEd deployed its management, supervision, and field force to exchange the 131,000 smart meters and install the RF communication system field network devices. By using its internal resources, ComEd was able to gain detailed insight into the issues that impact efficiency, safety, and quality of work. Several lessons were learned:

- Capturing meter location as part of the handheld is essential for asset and network management; existing systems were not capable of this activity.
- System installation and AMI operations are not the same activities or disciplines; they will overlap throughout the duration of the equipment installation period.
- Providing installers with paper orders to verify against the data in the handheld devices may reduce installation exception errors.
- During the installation of meters, digital pictures of final meter reading, suspected tampering conditions, damaged meters and non-compliant conditions should be captured for future reference.
- An audit procedure is needed to verify that the new meter type (form) matches the meter type subject to replacement.
- A variety of learnings on use of the meter installer electronic handheld device helped to improved the Pilot period installation performance and productivity (e.g., use of laser scanner improved battery life).

- Some company vehicles are more conducive for the meter field installation work than others.
- Unable To Complete (UTC) rates for meter work will be much lower than normal operations since the process includes pre-install notification letters, automated outbound phone calls, door knocks, and door cards to improve access.
- Schedule coordination at the meter supply "cross dock" can be help ease congestion while meters are loaded and unloaded at the start and end of shifts.

Information Technology Systems

As part of the Pilot, the AMI solution required several new IT systems, integration with existing systems and modifications to existing systems. Many different work groups were involved in the project development and subsequent on-going operations and support. Learnings in this area included:

- Communicate and socialize solutions across a broader spectrum of internal application owners and stakeholders to ensure expectations are aligned.
- Standardize and automate routine procedures (e.g., migrations and proactive monitoring) early in the project lifecycle to ensure consistency in execution and application performance.
- Continue to further leverage the findings of other utilities and the shared experiences of our vendor partners.
- Acknowledge schedule risks and implement mitigation plans early in project lifecycle.

A.2 Operations

Meter Reading

- While the AMI system is a highly reliable meter reading solution, there will remain a need to have a manual meter reading solution as a contingency for reading meters that may fail RF communication (i.e., the usage data is retained in the meter even if radio communication does not function).
- Given the need to have a backup manual meter reading solution, ComEd needs a proper test plan to ensure that the electronic handheld device software used by the meter readers can interrogate each type of smart meter before that type of meter is deployed in the field.
- The AMI system proved to be unaffected by harsh weather conditions such as a major snow storm (like the one experienced on February 1 and February 2, 2010). The storm severely impacted manual meter reading process on those days and several subsequent days. The AMI system continued to bring back 30 minute usage on all meters every day.

Billing

Billing simple rates like the standard residential rate worked well; however the project team had difficulty billing complex rates ("interval billed").

- Within the Pilot geographic "footprint", ComEd has 7,800 interval billed accounts made up of CAP and larger business customers.
- The meter data management system (MDMS) was not fully functional in June and July and could not automatically fill missing interval data due to power outages with zero values. ComEd knows the total usage registered on the meter and can confirm when missing data should be zero. Beginning with the last week of June, storms caused missing data affecting over 3,000 accounts. ComEd assigned

management personnel to a “war-room” starting in mid-July to address the missing data, fix system defects, and coordinate with the Billing department. This work closed late September.

- Automated Validation, Editing, and Estimating (VEE) and meter reading head-end fixes will need to be implemented prior to full deployment.

Remote Connect / Disconnect

As part of the Pilot, ComEd designed and developed systems to open and close the smart meters’ remote service switch for both move-in/move-out scenarios and for non-pay scenarios.

- The move-in functionality was enabled in 2010 and has worked reliably for the most part.
- Due to technical reasons, the move-out functionality was not implemented prior to winter.
- Due to an on-going Illinois Administration Code Part 280 revisions process, ComEd agreed to not use the switch for non-payment shut-offs until the revisions are completed.
- ComEd’s pilot experience with respect to opening the switch is limited to the use of the switch on inactive accounts in the summer of 2010.
- The switch worked well and reliably assuming network availability.
- When new customers called to establish service, the Connect (move-in) order processed through the AMI network automatically and the customer’s power turned on in minutes, if not less than a minute, and sometimes while the new customer was on the phone with ComEd’s customer service representative.

Theft/Tamper

During the Pilot operations period, ComEd identified many cases of customers tampering with their meter service. Identification occurred at the time the smart meter was being installed, after an inactive account was disconnected for unbilled usage, and in the normal course of AMI network monitoring.

- During the Pilot acceptance test, an inactive account was disconnected. Subsequently, the meter started alarming with last gasps (i.e., transmittal of last RF signals indicating a loss of power) and then went unreachable. An energy technician was dispatched to find that the customer had removed the meter and “jumpered” the service.
- ComEd has opened the switch on inactive accounts. A number of these meters have provided a “load side voltage” alarm and resulted in identifying customers who have self-restored with jumpers across the meter terminals.
- While the reverse energy channel is intended to allow for net-metering in the future, it also identifies customers who turn the meter upside-down in an attempt to “spin” the meter backwards. Cases of this type were also identified.
- ComEd has learned that unreachable meters after disconnect with a last gasp have a high likelihood of tamper and theft and require field trips to verify and remedy.
- ComEd fully expects to correlate events and learn even more about customer behavior and tampering as the pilot proceeds.

Outage Management

As discussed at the workshops, the learning opportunity related to the smart meter power status during storm events would be limited to storm conditions, something ComEd obviously could not predict. However, there were several storms during the Pilot that provided opportunities to "ping" meters over the network to determine customers' power status.

- On eight different dates, ComEd pinged meters at the end of storms to confirm status of single customer outage tickets.
- 272 out of 359 customer outage tickets were confirmed to have power and therefore the outage ticket could be closed. This avoided unnecessary truck rolls (and associated costs) and allowed ComEd crews to focus on customers with real outages.

In addition to the lessons learned from the actual storm event, ComEd also simulated outages with meters on four feeders. The network performed well and shows great promise for outage management in the future based on last gasp and power restoration message success rates.

- 100% of power restoration messages were received in all testing.
- Sufficient last gasp performance allowed the Outage Management System (OMS) to accurately identify the failed device in all tests.
- Next step testing with "grid-aware" meters may improve last gasp performance; "grid-awareness" will allow the smart meter to understand what device(s) it belongs to and route last gasp messages to meters belonging to different devices.

Call Center

ComEd created a select group of customer service representatives to answer AMI calls. All job aids and training were dedicated to these select individuals. The majority of calls were high bill complaints due to:

- High, above normal temperatures during the summer of 2010.
- The last bill with the old meter was based on an estimated read.
- The final read off the old meter was incorrect at the time of exchange.

CSRs effectively utilized the on-demand read from the meter, leveraging the AMI network to help address these complaints. Additionally, call volume dropped off dramatically after the summer period.

Meters

Based on realizing the business case benefits and maximizing operating excellence, ComEd plans to ensure that the smart meters for future AMI deployment meet the following functional requirements:

- Ability for remote two-way communications with the meter.
- Ability to capture 30-minute interval data on multiple channels.
- ANSI C12.19 standards compliant.
- Internal disconnect/re-connect service switch.
- Bi-directional metering.
- Ability to remotely upgrade all components of meter firmware (communications, metrology, and home area networking)
- Voltage sensing.
- Power quality measurement.

- Meter events.
- Temperature sensing.

ComEd found that the network testing environments need to improve as a result of the pilot. ComEd's test environments require a full representation of all meter models using real meters to test reads, disconnects, firmware and other meter programming nuances that cannot be easily simulated.

Network

- For the Pilot "footprint" and to cover the 131,000 meters, ComEd deployed a sparse RF communications network in order to learn more about the network. Initially, ComEd intended to deploy network infrastructure at a ratio of 6,000:1 meters to "Access Points". As a result of network optimization, ComEd ended up with ratio of approximately 4,800:1.
- ComEd found the network to be efficient and more than sufficient for the operational needs explored during the pilot.
- Mass firmware downloads to all of the meters proved the most effective method even when only select meters require the firmware updates. This learning was identified when attempting to update certain CAP customers' meters that were not geographically clustered.
- Geographic mapping tools for meter locations will help identify pockets of poor network communications performance between meters that need to be remedied.

Connectivity to the Home Area Network (HAN)

While out of scope of this evaluation, ComEd also used the Pilot to explore CAP program elements. As part of the CAP program, ComEd provided customers with in-home technologies (basic in-home device, enhanced in-home device) capable of receiving pricing signals and displaying real-time usage directly from the meter leveraging ZigBee SEP 1.0 communications. (All Pilot meters included the ZigBee SEP 1.0 communications capability).

While in-premise communications worked, progress is needed to improve usability and connectability, especially in scale.

- ComEd noted issues with firmware and security "certificates."
- Some issues were identified (and resolved) with in-premise devices losing authentication and re-connecting to the network.
- No significant RF issues (meter to in-premise device) were identified.
- ComEd perceives that the technology is not mature; a "plug-n-play" business and system model where in-premise devices can be purchased through third-party suppliers is not in place or feasible at this time.

A.3 Customer Experience

A concerted effort was made as part of the Pilot to ensure the customer's positive experience and quickly address customer concerns in any aspects of the project scope. In addition, ComEd used a market research firm to measure and assess customers' satisfaction with the meter installation process.

Installation Process

The meter installation communication process included several steps:

- Pre-install letter sent out three weeks prior to week of install
- Pre-install automated outbound call one week prior to install
- Door knock immediately prior to meter exchange
- Door hanger explaining new meter
- Door hanger explaining the reason a new meter couldn't be installed (if applicable)

While overall customer satisfaction with the installation process was 90% (based on the survey results), there were learnings identified through the satisfaction surveys:

- The placement of the door card was reinforced with the field technicians, and the process for multiple occupancy buildings was revised.
- To address non-English speakers in the Humboldt Park network footprint, a Spanish translation was added to the automated phone message.
- The ComEd web site, www.comed.com\smartmeter, was improved. The website contains additional information for the customer, including information about the installation process, a pilot overview, FAQs, and information about how to read a smart meter.
- A car magnet was created to raise customers' awareness regarding the field technicians who were in the neighborhood installing smart meters.

Escalated Inquiries/Complaints

To address potential escalated complaints, the project design included:

- Seven specialized call center reps for customer calls
- Single Point Of Contact (SPOC) for escalated questions/concerns
- Rapid response team including executives to address escalated complaints
- Expedited claims review process to better expose extent of condition issues that new technology may introduce

ComEd did experience customers reporting possible disruption to their home appliances/equipment at the time of the meter installation. ComEd managed these issues on a case-by-case basis:

- Two cases of interference were identified in the field with a baby monitor and a cordless phone.
- Seven cases of performance issues related to motion detection lights.
- The potential loss of exotic fish in the event of a temporary power loss.
- Loss of refrigerated medical supplies due to a meter exchange was addressed.

Two premises refused a smart meter because of potential of health issues. ComEd continues to work with these customers to address concerns.

Finally on three occasions and at customers' requests, ComEd performed field testing of meter accuracy where an electro-mechanical meter and a new AMI meter were placed in a dual-socket meter adapter that allowed both meters to monitor the customer's usage. In all three cases, the smart meter recorded usage accurately.

A.4 Web Presentment of Detailed Energy Usage

ComEd provided all Pilot-area customers with access to their daily interval data via the web. Over 4,000 customers enrolled with over 300 active users.

The following conditions prevent certain customers from using the application:

- Multiple metered residential accounts (this is a rare situation).
- The application's inability to determine accurate neighbors for the usage comparison feature.
- Unavailable data display due to the meter's inability to communicate with the AMI network.

The website required a separate customer log-in. The majority of the issues that customers ran into were related to the initial creation of the account. The account number and the name on the ComEd bill had to exactly match for customers to create an account on the Smart Tools website. These instructions were provided in the letter to the customer.

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Appendix B: Business Case Assumptions

	Name / Description	As-Is Assumption (no automation)	To-Be Assumption (assumes AMI)
Meter Reading and Field Meter Services			
1	Meter Read Performance System-Wide / All Meters	88% blended average of all meters installed at end of 2010	99.5% (steady state); increases proportionally during deployment
2	Random Samples	All random samples will be performed per regulations	
3	Periodic Exchanges	All periodics will be performed per regulations	
Revenue Management			
4	Cuts - Residential	115k - years 2011-2020	Cut 100% of those eligible to be cut as soon as allowed by regulations. 180k (remote); 9k (manual); field orders are needed for 3% RDS exceptions and switchless meters
5	Cuts - SCI/LCI[83]	5k - years 2011-2020	Cut 100% of those eligible to be cut as soon as allowed by regulations. 13k (remote); 3k (manual); field orders are needed for 3% RDS exceptions and switchless meters
6	Cut In (Reconnect)	75k - years 2011-2010	9,500 Cut-In's requiring a field trip are required for payments made on ~75% of manual disconnects
Revenue Protection			
7	Move Out (Finaled)	723k move-outs annually	678k with switch-capable meter; Disconnects will not be fielded unless CIM WFM is generated
8	Move In (Connect)	716K move-ins annually	671K with switch-capable meter; 6,600 Move-In's require field trip after a failed remote connect (1% RDS failure)
9	CIM Orders	Continue at same volume as in 2011 (49k)	7,500 Move-Out's require field trip after a consumption on inactive WFM generated on premises w/o RDS or with a failed remote disconnect
10	CCM[84] Orders	8k in 2011 to 6k in 2013; 6k per annum thru 2030	1,000 (8%) of manually cut meters may still require a field investigation
11	Theft / Tampering Investigations	Trend up annually consistent with meter growth - 9,500 annually	Significant reduction in field originated and non-specified rev pro orders - 2,500 annually
Meter Growth			
12	Meter Growth Rate	0.5% annually (not compounded) (i.e., 20k new meters annually)	

[83] SCI/LCI – Small and Large Commercial and Industrial customers

[84] CCM stands for Consumption on Cut Meter whereas ComEd recognizes that there is consumption at a meter that has been disconnected.

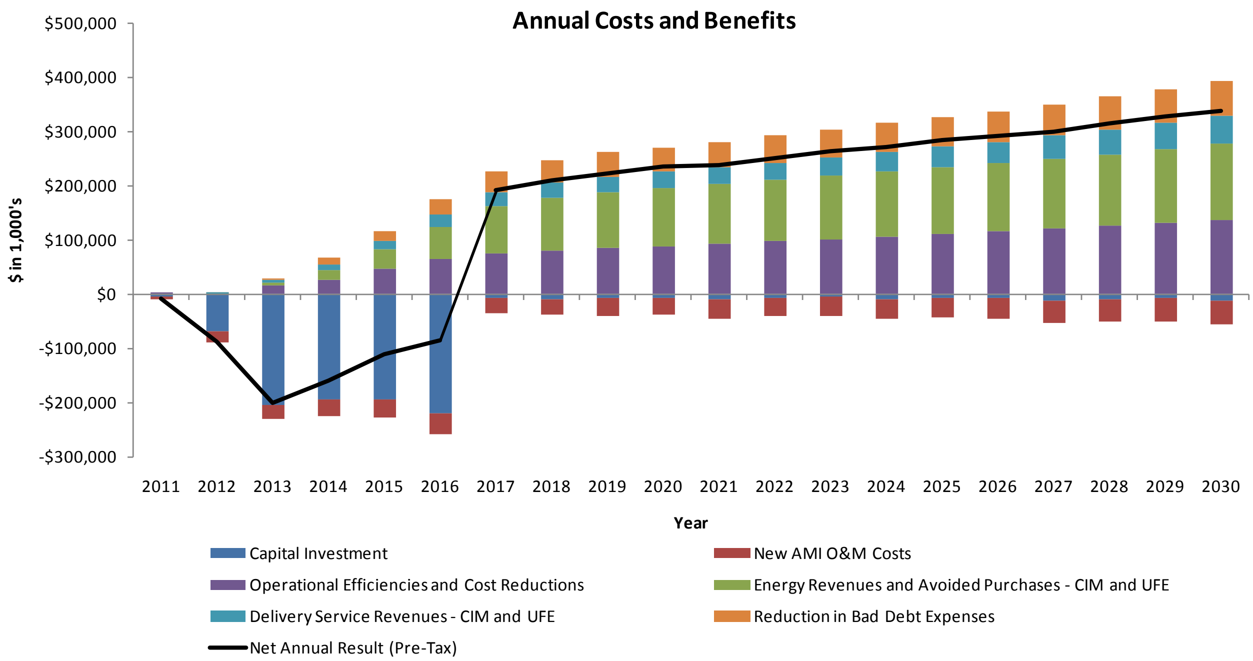
	Name / Description	As-Is Assumption (no automation)	To-Be Assumption (assumes AMI)
13	RRTP[85]	1,800 annually due to word-of-mouth growth	RRTP requests addressed with AMI meters
14	Competitive Declarations	Approximately 0.5% or 500 meters annually	Com Decs addressed with AMI meters
AMI Deployment and AMI Operations			
15	Transition Meter Readers to F&MS (Installs and Meter Safety Order Inspections)	N/A	Excess Meter Readers transition to F&MS for AMI installs and AMI meter inspections (min. of 40 FTE)
16	Remote Disconnect Success Rate	N/A	97%; 3% will require manual disconnects/connects
17	Meter Investigations	N/A	86,000 new investigations, inclusive of tamper, theft and other communications alarms or events (40,000 non-theft)
18	Deployment for Growth and Exchanges	N/A	AMI addresses growth and exchanges Day 1 of deployment
19	"Door Knock" on Disconnect/Reconnect[86]	Per Illinois Administrative Code part 280	No door knock is required
20	AMI Meter Failure Rate	N/A	1% annually
21	Warranty Support	N/A	Warranty of 60 months on hardware only; warranty on field trip costs in the event of a catastrophic or infant failure > 3%
Billing			
22	Reduction of Billing FTE	N/A	56% reduction in billing orders (Res. and C&I)
Call Center			
23	Reduction of Call Center FTE	N/A	Negligible call reduction with offsetting increases due to new call volume related to the Smart Meter technology and benefits
Finance			
24	Pensions and Benefits	N/A	Individual P&B amounts calculated specifically for Meter Reading and F&MS. Billing and Call Center estimates will use ComEd general rate
25	Energy and Delivery Costs	Annual values provided by Finance	
26	AMI Pilot	Pilot costs are "sunk" and not included in the model	Pilot costs are "sunk" and not included in the model

[85] RRTP stands for Residential Real Time Pricing. The RRTP program at ComEd provides TOU-capable meters to customers upon request.

[86] "Door knock" here is used to refer to potential requirements ComEd may have to notify customers in the event of a service disconnect or reconnect. At this point, there are no clear requirements re: specifically what activities are included within a "Door knock". For purposes of the evaluation, it is used to indicate some notice requirements, the nature of which may change.

Appendix C: Business Case Model—Graphs and Illustrations

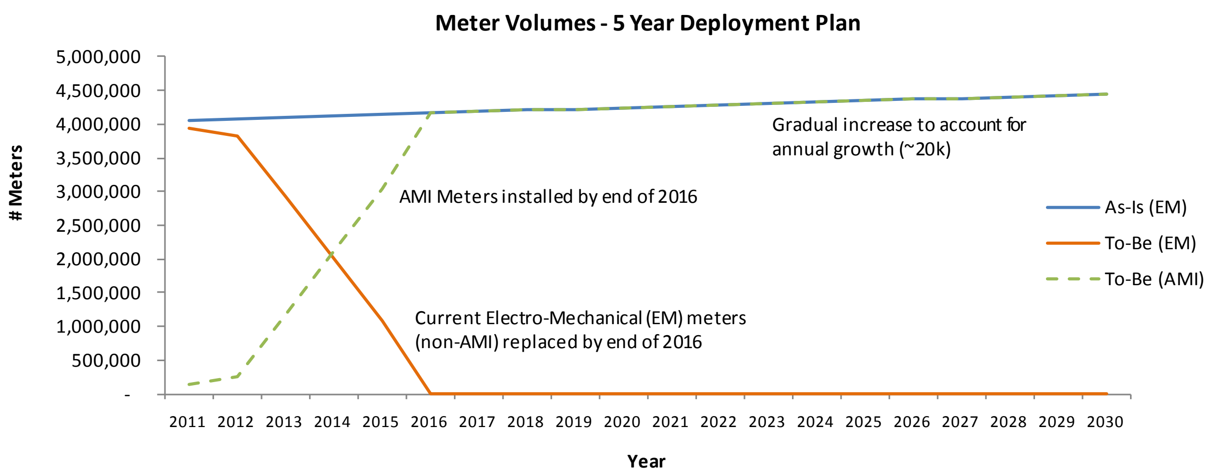
C.1 Business Case Evaluation—Costs and Benefits

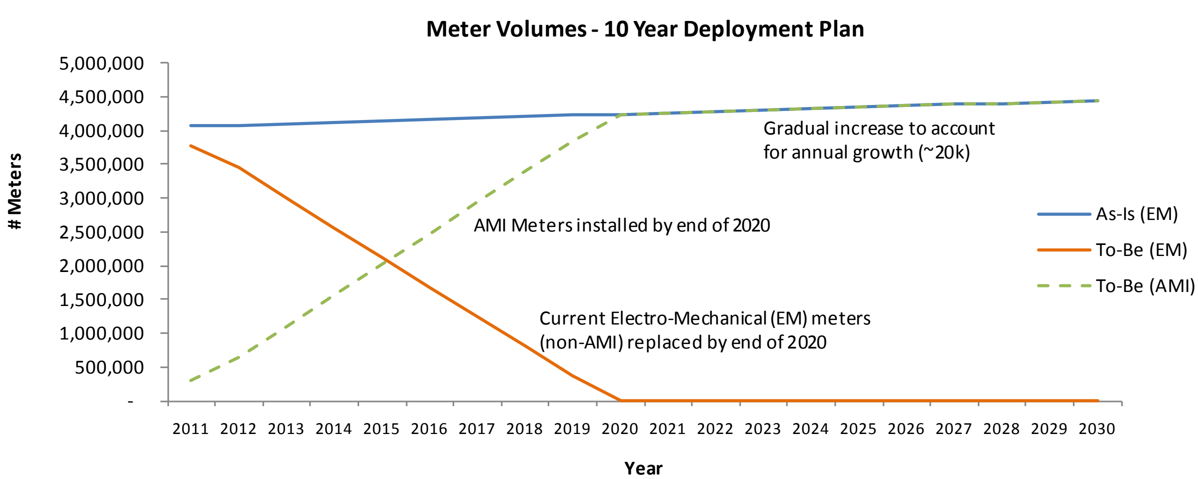


C.2 Meter Population Estimates

ComEd Meter Population Estimates

Current and AMI Meter Annual Volumes (5 and 10 year Deployment)

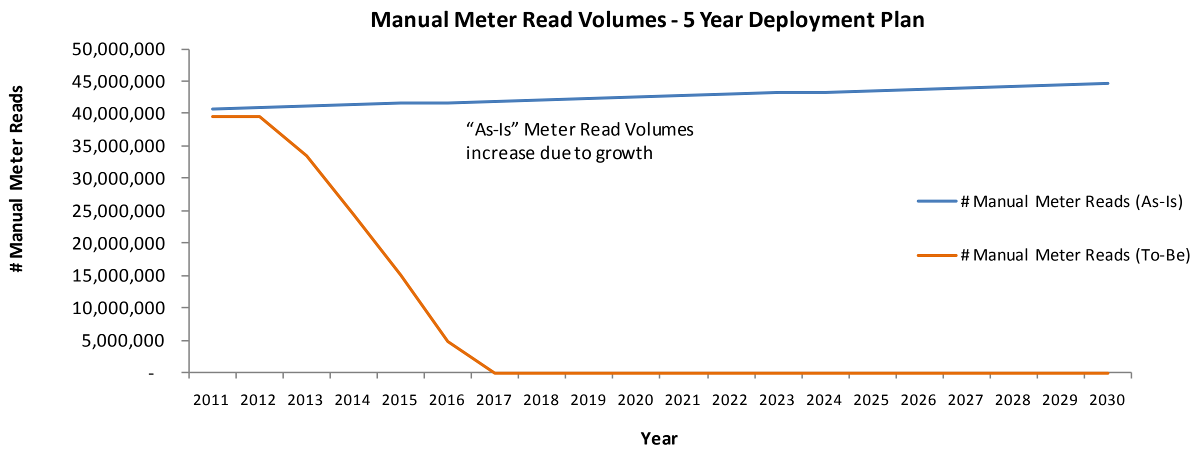


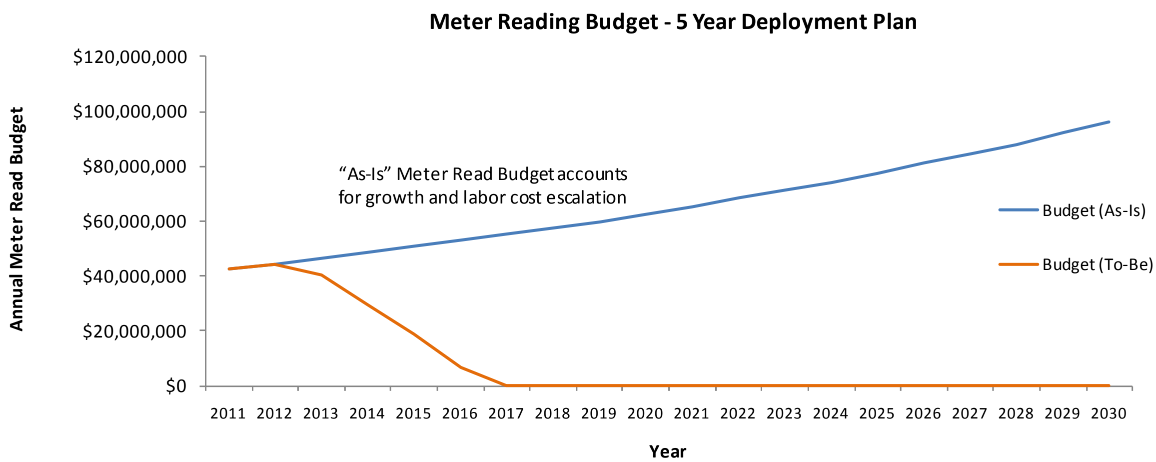


C.3 Monthly Estimated Meter Read Requirements and Estimated Budget Impact

ComEd Manual Meter Reading

Monthly Estimated Meter Read Requirements and Estimated Budgets (“As-Is” and “To-Be”)





- FTE’s ramped-down proportional with the required manual meter read, decreasing throughout the AMI deployment
- 3 month of lag is built into the Budget phasing relative to the volume of manual meter reads to account for adequate time for testing and certification of the AMI meter to communicate via the AMI network
- Elimination of manual meter reads ultimately results in proportional reduction and eventual elimination in the Meter Reading budget
- 2017 “As-Is” vs. “To-Be”: 546 FTE reduction
- 2017 Budget Savings: $53.5M

C.4 F&MS Activities, FTE Requirements, and Estimated Budget Impact

F&MS Activities, FTE Requirements, and Estimated Budget Impacts (“As-Is” and “To-Be”) - 5 year Deployment

Activities

FMS Activity	As-Is (2011)	To-Be Steady State (2017)
Regulatory	47,701	60,583
Revenue Work	479,480	139,298
Customer Maintenance	21,710	22,309
AMI Meters	0	86,200
AMI Inspection and Reads	0	1,070,134
TOTAL	548,892	1,378,525

FTE

Role	As-Is (2017)	To-Be (2017)
Indirect-Ind Contrib E2	20	20
Ind Contrib E3-Supervisor-D	19	19
Indirect-Ind Contrib E4	4	4
Indirect-Director E6	1	1
Clerical	22	22
Mechanic Electronic	3	3
Mechanic Meter Equipment	1	1
Meter Mechanic Special	6	6
Senior Energy Technician	113	72
Energy Technician	98	67
Primary Energy Technician	7	6
ET - Disconnect (Upgrade MR)	33	0
AMI Meter Inspector	0	40

Field Tech FTE Reqs. reduced from 251 to 185

Estimated Budget
(no labor cost escalation applied)

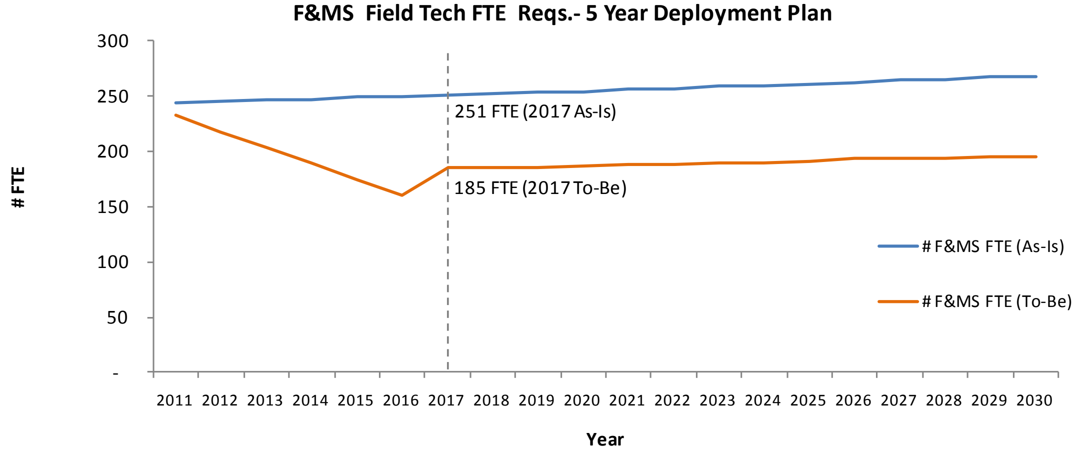
"As-Is" 2011 Budget (in $1,000's)		"To-Be" 2017 Budget (in $1,000's)	
O&M			
Base Payroll	19,818	Base Payroll	15,077
Overtime & Premiums	1,098	Overtime & Premiums	641
Staff Augmentation	192	Staff Augmentation	-
Pensions & Benefits	15,019	Pensions & Benefits	11,836
Contracting:	1,173	Contracting:	858
Transportation	2,228	Transportation	1,563
Materials	1,299	Materials	1,299
Office & Postage	34	Office & Postage	34
Travel/Meals	268	Travel/Meals	268
Other Expenses	86	Other Expenses	86
Subtotal	41,215	*Subtotal*	31,663
Capital			
Base Payroll	4,289	Base Payroll	4,062
Overtime	120	Overtime	120
Other Premiums	28	Other Premiums	-
Pensions & Benefits	3,255	Pensions & Benefits	3,183
Payroll Taxes	410	Payroll Taxes	377
Transportation	470	Transportation	427
Materials	7,649	Materials	10,097
Office & Postage	4	Office & Postage	4
Travel/Meals	11	Travel/Meals	11
Other Expenses	110	Other Expenses	110
Subtotal	16,347	*Subtotal*	18,391
TOTAL O&M and Capital	57,562		50,054

Types of Activity

All F&MS field activities (~ 40 individual activities) are grouped into the following 5 categories of work:

- Regulatory – Mandatory regulatory activities to test and/or replace meters for both C&I and Residential customers
- Revenue Work – Meter activities related to managing consumption (connect, disconnects, theft/tampering, etc.)
- Customer Maintenance – Activities to repair, replace, or remove meters; generally triggered by customer requests
- AMI Meters – Activities resulting from theft/tampering alerts that the AMI meters will be capable of producing
- AMI Inspection and Reads – Required AMI meter inspections and residual manual meter reads as necessary

F&MS Field Tech FTE Reqs.- 5 Year Deployment Plan

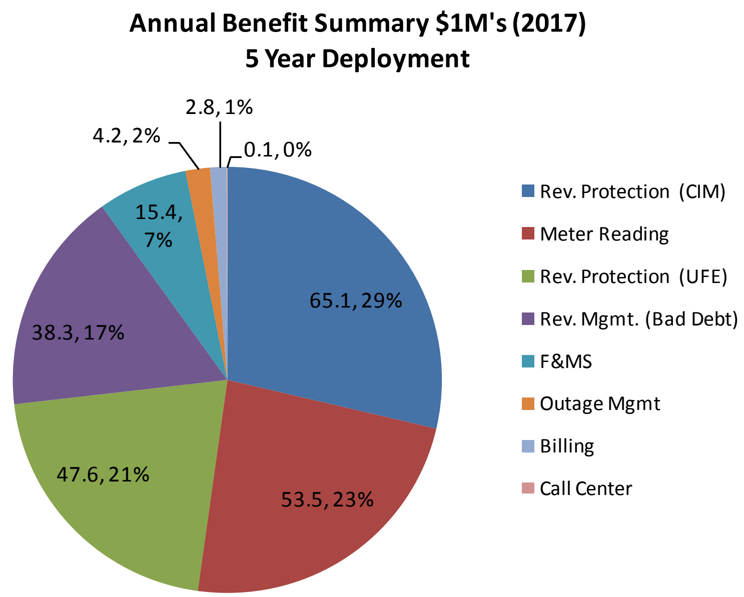


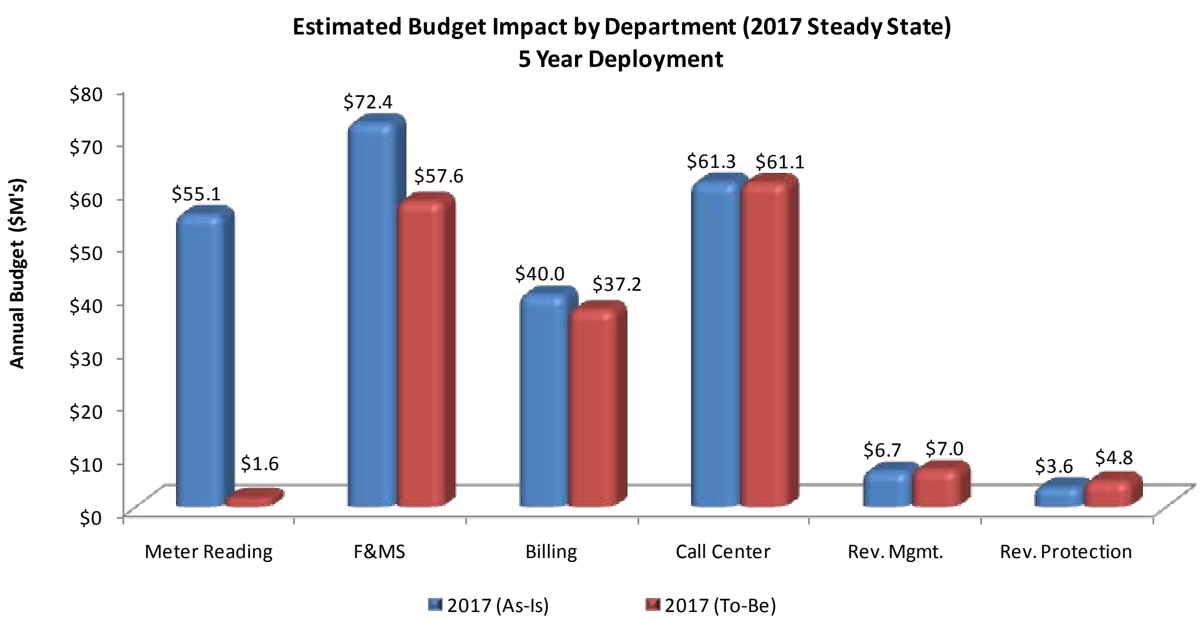
- Field Tech’s (illustrated in graph above) make up a segment of the F&MS work force
- 2017 “As-Is” vs. “To-Be”: 66 FTE reduction
- 2017 Budget Labor Savings: $14.8M
- Results includes growth (FTE) and escalation ($)

C.5 *Benefit Summary and Estimated Budget Impacts (by Department)*

Benefit Summary and Estimated Budget Impacts

Estimated Benefits & Budget Impact ("As-Is" and "To-Be") – 5 year Deployment



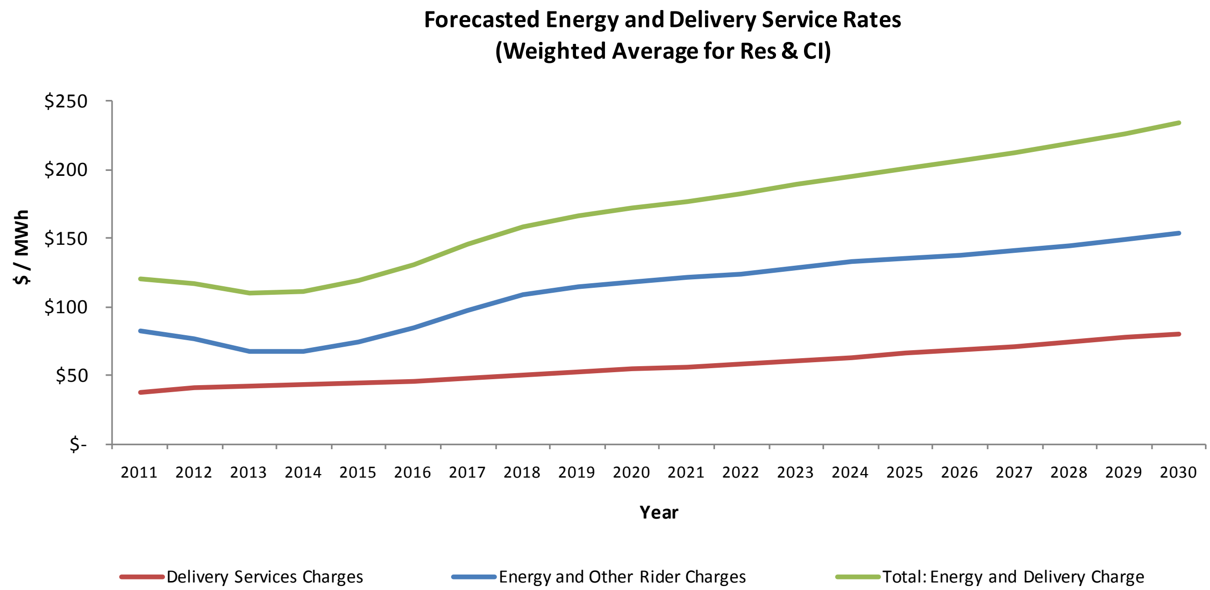


** F&MS – Doesn't reflect net change in meter capital. While these AMI meter capital costs are included, the estimated budget impact for this FMS area simply reflects the O&M cost savings.*

*** Remaining Meter Reading budget in 2017 ($1.6M) represents the 3-month lag in recognizing these benefits after deployment of AMI meters*

C.6 *Forecasted Retail Energy and Delivery Prices*

Forecasted Retail Energy and Delivery Prices



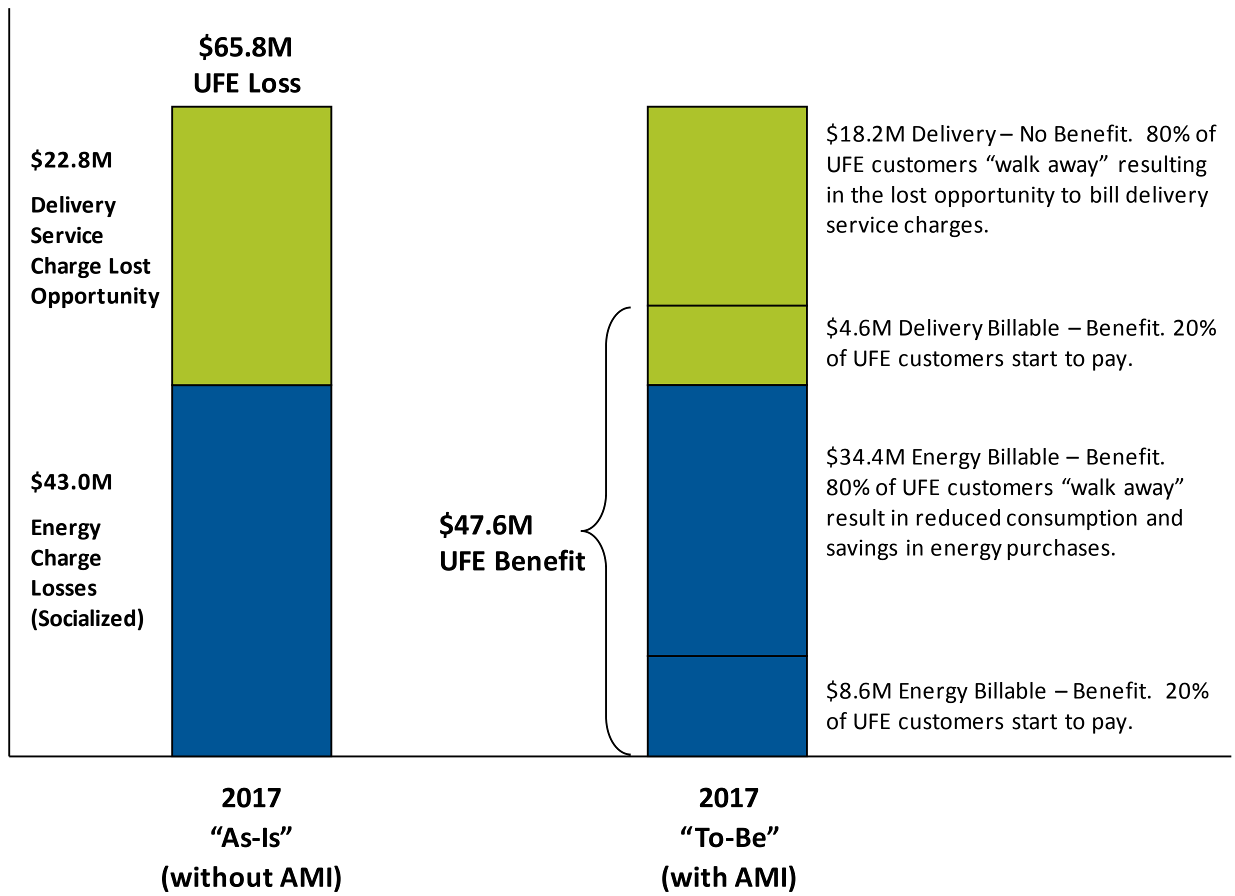
Energy + Delivery Charges: Avg. Annual Change (20 yrs) = ~3.8% increase

** As illustrated and listed above, the bundled charge of electricity (energy + delivery services) is forecasted to increase, on average, by 3.7% annually. This escalation of the energy and delivery charges has the largest impact on the business case as it is directly used in the calculation of the UFE, CIM, and Bad Debt benefits. Refer to the Sensitivity Analysis for business case results for an adjusted energy and delivery services escalation factor.*

C.7 Unaccounted for Energy (UFE) – Theft / Tampering

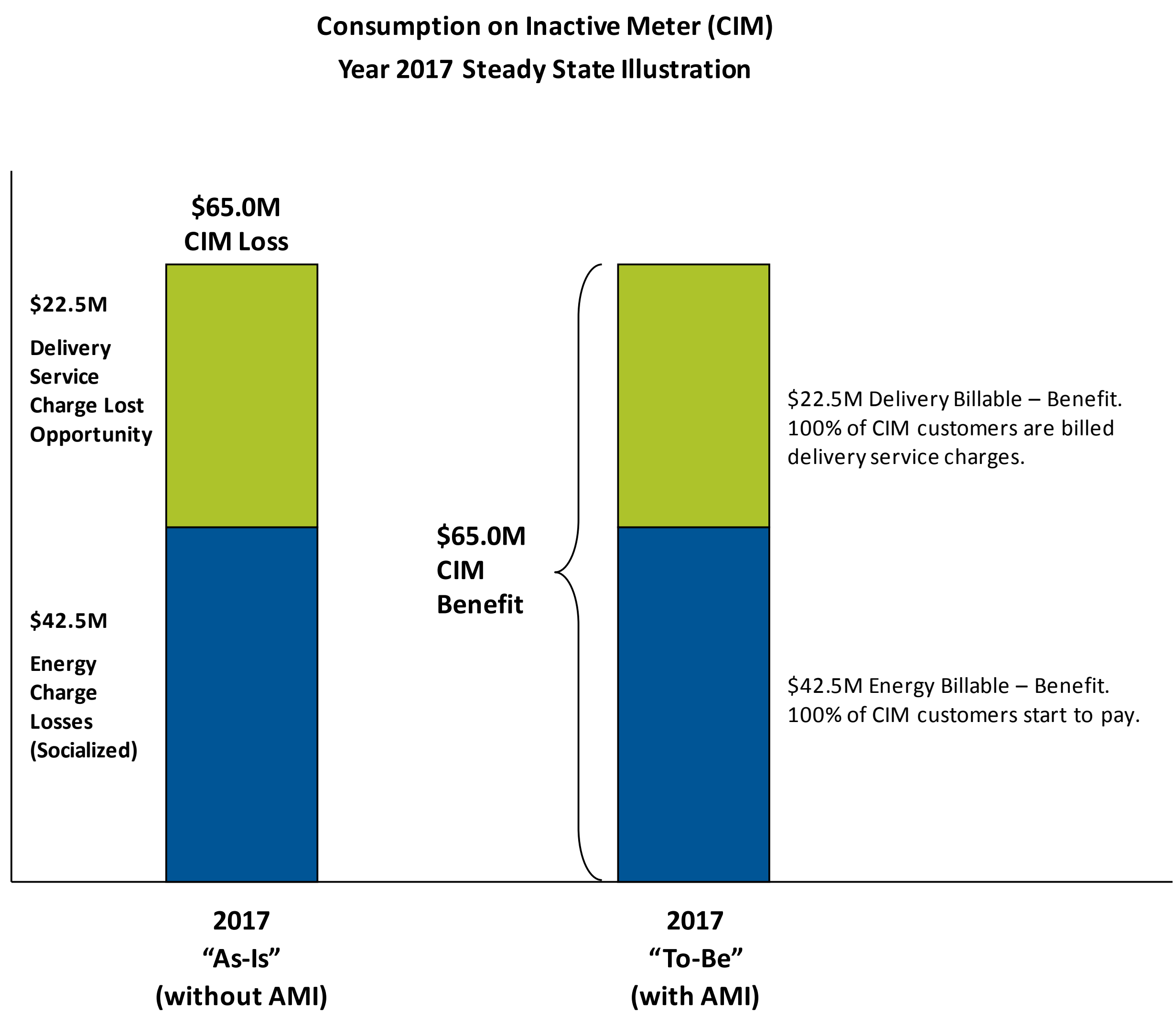
Unaccounted for Energy (UFE) – Theft / Tampering

Year 2017 Steady State Illustration



** Escalation Applied. This graphs only illustrates the costs and potential savings of the "realizable" UFE consumption due to theft/tampering base case assumes 50% of UFE kWh can be realized as benefit with improved AMI technology and business processes. Refer to UFE Benefit Description in Appendix for details.*

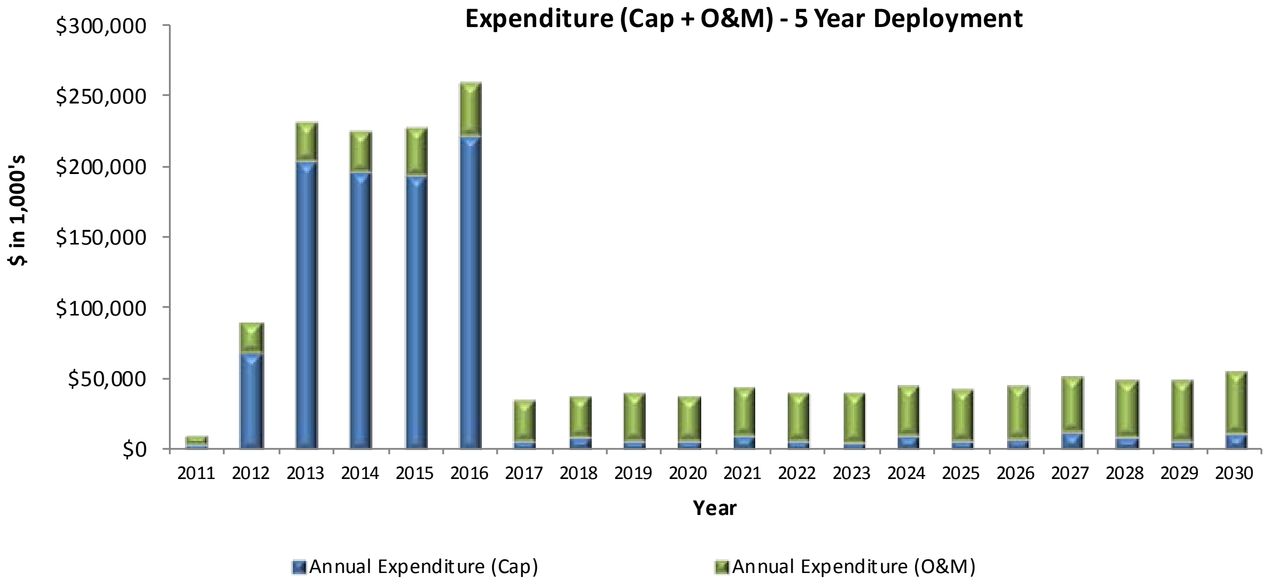
C.8 Consumption on Inactive Meter (CIM)

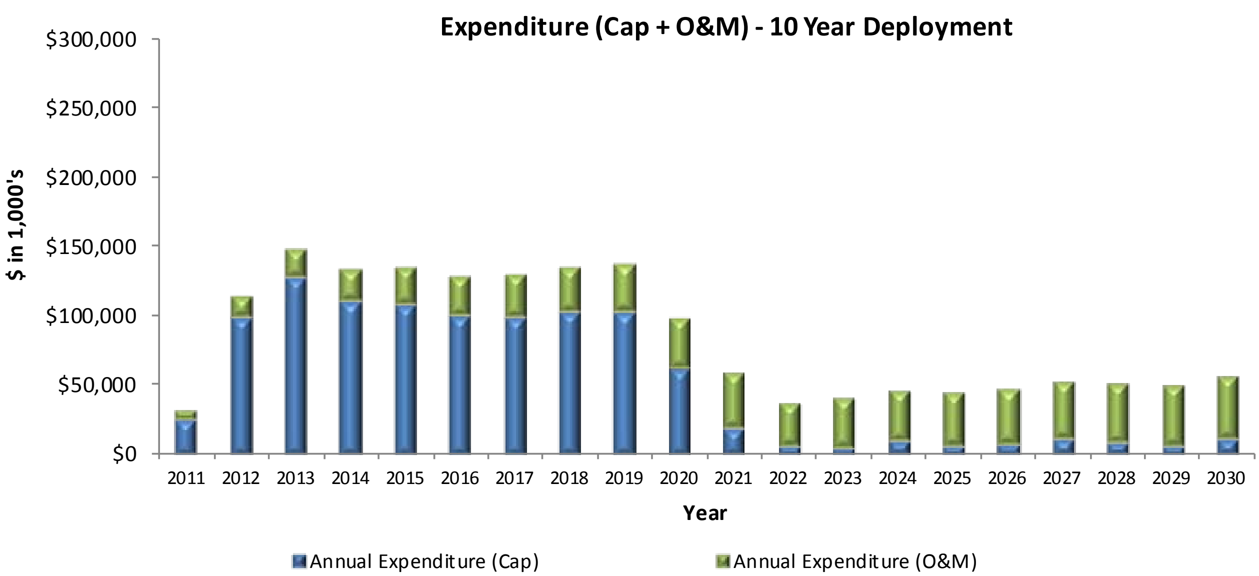


** Escalation Applied. In the estimated benefit of CIM, the base case of the evaluation assumes that 90% of the current CIM losses are achievable. Additionally, of the achievable benefit, 100% of the consumption becomes billable and paid – resulting in 100% of the delivery service charges are recognized as a benefit. As part of the Sensitivity Analysis, an evaluation was also performed to identify the impact on the benefit if 0% of the customers become billable and pay. In this sensitivity case, only the energy is recognized as a benefit (avoided power purchase costs).*

C.9 Expenditure Summary (Capex + O&M)

Expenditure Summary (Capex + O&M)
Annual and Cumulative– 5 and 10 year Deployment



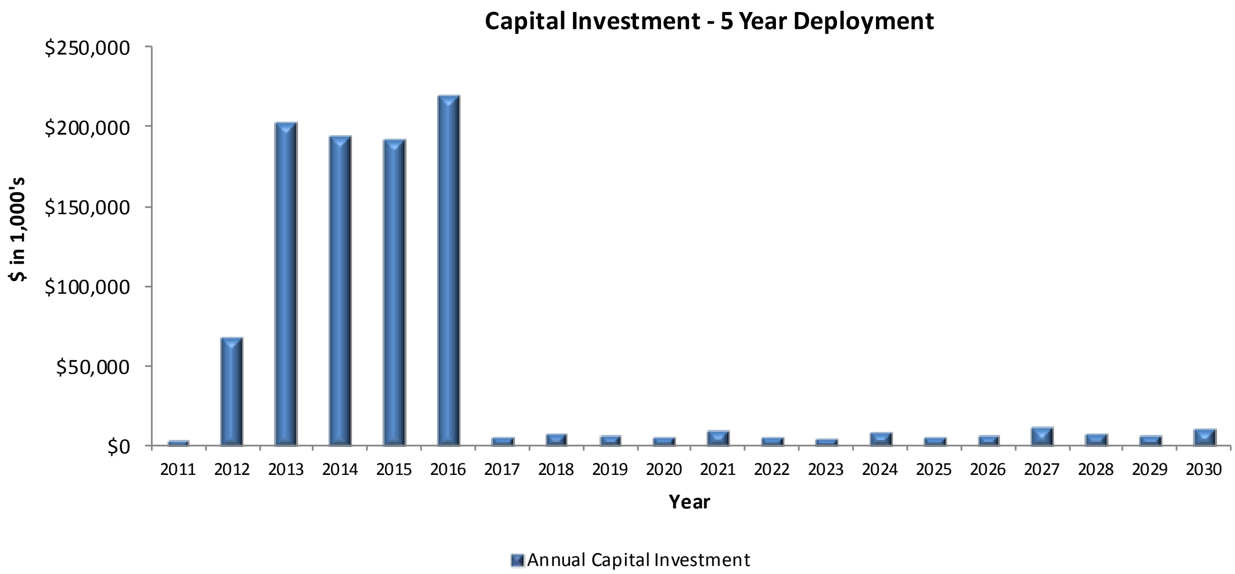


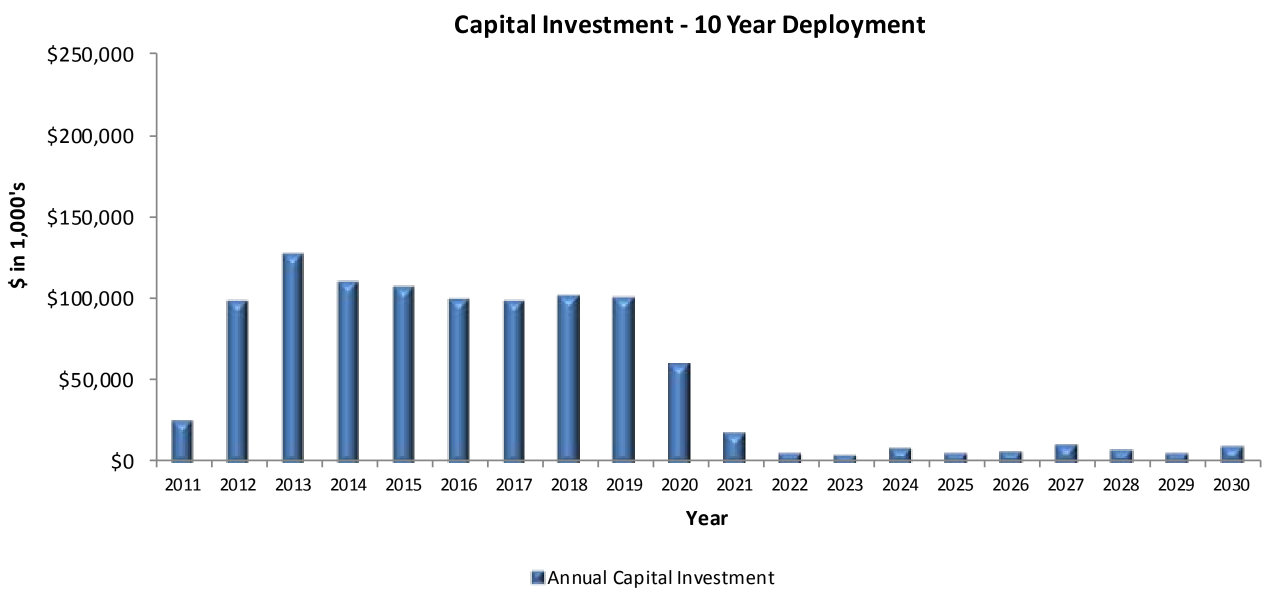
** In the 5-Year Deployment Plan, cumulative expenditures (Capital + O&M) equate to $1.66B. In the 10-Year Deployment Plan, cumulative expenditures (Capital + O&M) equate to $1.68B.*

C.10 Capital Investment Summary

Capital Investment Summary

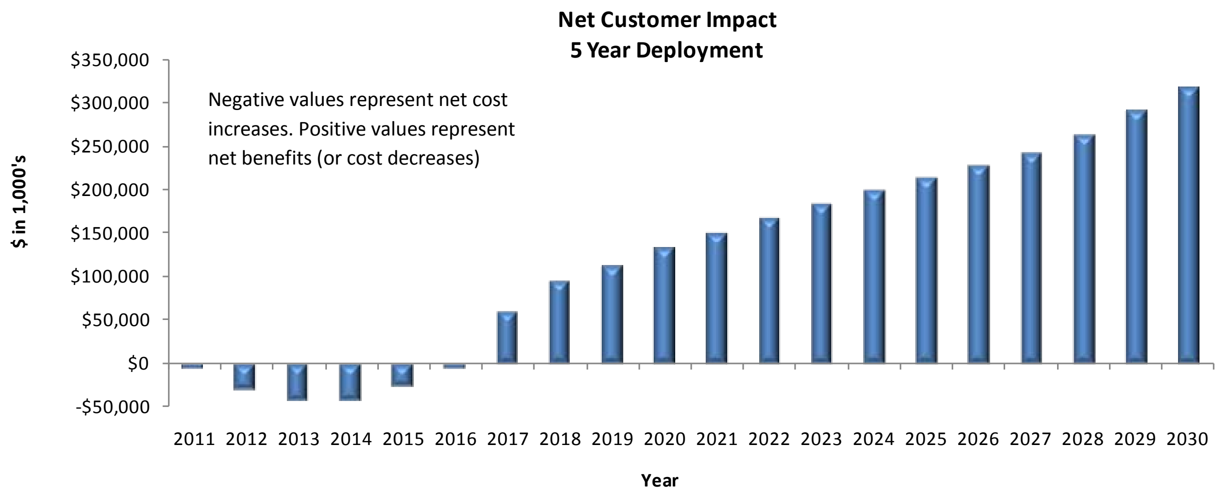
Annual and Cumulative Capital Investment – 5 and 10 year Deployment





** In the 5-Year Deployment Plan, cumulative Capital investment equates to $995M. In the 10-Year Deployment Plan, cumulative Capital investments equate to $1,030M.*

C.11 Net Customer Impact



Cumulative $ over 20-year evaluation period.

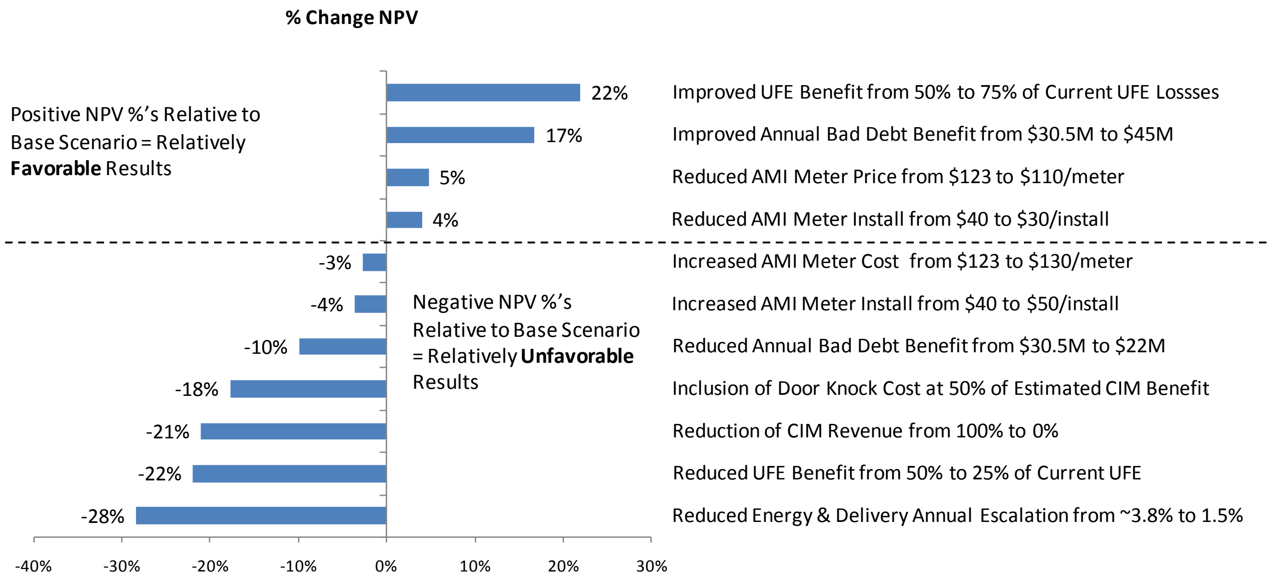
	Total Estimated Impact on Rates
Change in Distribution Revenue Requirements (Before Accounting for Customer Benefits Below)	-$620 million
Increase in Customer Benefits – UFE, CIM, and Bad Debt	$3,113 million
Net Change in Customer Cash Flow (Considering all AMI Costs and Benefits)	$2,493 million
NPV *	$1,296 million

** NPV based on discount rate = 4.27% (20-yr treasury).*

C.12 Sensitivity Analysis - Results Summary

Sensitivity Analysis - Results Summary

Base Case (5 Year Deployment) has a 20 Year NPV = **$1,296 million**.*



** NPV's calculated based on 4.27% discounted rate of return.*

Appendix D: Business Case Model Excerpts

D.1 Results and Sensitivity Analysis (Scenarios A-F)

Business Case Impact	**N/A**	**Unfavorable**	**Favorable**	**Unfavorable**	**Unfavorable**	**Favorable**	**Unfavorable**
Item	**Base Case (5 year Deployment)**	**A. Energy Price Escalation Factor (1.5% E&D)**	**B. AMI Meter Prices ($110/meter)**	**C. AMI Meter Cost ($130/meter)**	**D. UFE - Achievable Benefit (25% kWh)**	**E. UFE - Achievable Benefit (75% kWh)**	**F. CIM - % Billable (0%)**
Costs (Cumulative 20 years)							
O&M Expense for Smart Meter System	$665.3	$665.3	$665.3	$665.3	$665.3	$665.3	$665.3
New Capital Investment for Smart Meter System	$995.8	$995.8	$941.5	$1,026.4	$995.8	$995.8	$995.8
Sub-Total	***$1,661***	***$1,661***	***$1,607***	***$1,692***	***$1,661***	***$ 1,661***	***$1,661***
Operational Benefits & Delivery Service Revenues (Cumulative 20 years)							
Operational Efficiencies and Cost Reductions	$1,625.2	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,630.4
Avoidance of Capital Expenditures	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4
Delivery Service Revenues – UFE and CIM	$564.2	$414.5	$564.2	$564.2	$516.7	$611.7	$95.0
Sub-Total	***$2,192***	***$2,048***	***$2,198***	***$2,198***	***$ 2,151***	***$2,246***	***$1,729***
Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cumulative 20 yrs)							
Reduction in Purchased Power Costs - UFE and CIM	$707.5	$563.2	$707.5	$707.5	$353.8	$1,061.3	$1,581.6
Energy and Other Revenues - UFE and CIM	$1,051.0	$836.7	$1,051.0	$1,051.0	$962.5	$1,139.4	$176.9
Reduction in Bad Debt Expenses	$790.7	$612.4	$790.7	$790.7	$790.7	$790.7	$790.7
Sub-Total	***$2,549***	***$2,012***	***$2,550***	***$2,550***	***$2,107***	***$2,991***	***$2,550***
Total / Net (Cumulative 20 years)							
Net Total (Benefits Less Costs)	***$3,081***	***$2,400***	***$3,140***	***$3,056***	***$2,596***	***$3,576***	***$2,617***
Net Present Value (NPV)	***$1,296***	***$931***	***$1,360***	***$1,264***	***$1,014***	***$1,583***	***$1,026***
Discounted Payback (Yrs)	**8**	**9**	**8**	**9**	**9**	**8**	**9**

*All values in $ Millions. * NPV calculated based on discount rate = 4.27%*

D.1 Results and Sensitivity Analysis (Scenarios G-L)

Business Case Impact	**N/A**	**Unfavorable**	**Favorable**	**Unfavorable**	**Favorable**	**Unfavorable**	**N/A**
Item	**Base Case (5 year Deployment)**	**G. AMI Meter Install Cost - $50/install**	**H. AMI Meter Installation Cost ($30/install)**	**I. Bad Debt Expense ($22M)**	**J. Bad Debt Expense ($45M)**	**K. Door Knock Disconnect (50% of Benefit)**	**L. Base Case (10 year Deployment)**
Costs (Cumulative 20 years)							
O&M Expense for Smart Meter System	$665.3	$665.3	$665.3	$665.3	$665.3	$1,055.7	$652.6
New Capital Investment for Smart Meter System	$995.8	$1,037.1	$950.3	$995.8	$995.8	$995.8	$1,030.6
Sub-Total	***$1,661***	***$1,702***	***$1,616***	***$1,661***	***$1,661***	***$2,052***	***$1,683***
Operational Benefits & Delivery Service Revenues (Cumulative 20 years)							
Operational Efficiencies and Cost Reductions	$1,625.2	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,630.4	$1,539.4
Avoidance of Capital Expenditures	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4
Delivery Service Revenues – UFE and CIM	$564.2	$564.2	$564.2	$564.2	$564.2	$564.2	$531.3
Sub-Total	***$2,192***	***$2,198***	***$2,198***	***$2,198***	***$2,198***	***$2,198***	***$2,074***
Additional Benefits (Energy, Transmission and Other Rider Cost Reductions and Revenues) (Cumulative 20 yrs)							
Reduction in Purchased Power Costs - UFE and CIM	$707.5	$707.5	$707.5	$707.5	$707.5	$707.5	$667.1
Energy and Other Revenues - UFE and CIM	$1,051.0	$1,051.0	$1,051.0	$1,051.0	$1,051.0	$1,051.0	$991.3
Reduction in Bad Debt Expenses	$790.7	$790.7	$790.7	$569.6	$1,165.1	$790.7	$745.1
Sub-Total	***$2,549***	***$2,549***	***$2,549***	***$2,328***	***$2,924***	***$2,549***	***$2,403***
Total / Net (Cumulative 20 years)							
Net Total (Benefits Less Costs)	***$3,081***	***$3,045***	***$3,132***	***$2,865***	***$3,461***	***$2,696***	***$2,795***
Net Present Value (NPV)	***$1,296***	***$1,252***	***$1,350***	***$1,170***	***$1,516***	***$1,069***	***$ 1,152***
Discounted Payback (Yrs)	**8**	**8**	**8**	**9**	**8**	**9**	**9**

*All values in $ Millions. * NPV calculated based on discount rate = 4.27%*

D.2 AMI Driven Benefits

AMI Driven Benefits	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	1.000	1.005	1.010	1.015	1.020	1.025	1.030	1.035	1.040	1.045	1.050	1.055	1.060	1.065	1.070	1.075	1.080	1.085	1.090	1.095
	($1,000s) -->																			
UTILITY: Items that Impact O&M																				
Related to the Meter Reading Function																				
Elimination manual reading expenses: Direct Labor	0.0	0.0	3,464.7	9,841.6	17,507.9	26,344.5	32,705.5	35,167.7	36,709.5	38,360.3	40,015.9	41,857.7	43,683.7	45,537.4	47,559.2	49,667.8	51,794.2	53,988.9	56,462.0	59,026.1
Elimination manual reading expenses: Incentive	0.0	0.0	152.5	433.2	770.7	1,159.7	1,439.8	1,548.1	1,616.0	1,688.7	1,761.6	1,842.7	1,923.0	2,004.6	2,093.6	2,186.5	2,280.1	2,376.7	2,485.6	2,598.4
Elimination manual reading expenses: Benefit and Pensions	0.0	0.0	359.6	3,888.2	7,602.9	11,399.6	14,150.4	15,221.4	15,871.8	16,599.3	17,325.0	18,111.1	18,899.8	19,705.6	20,605.4	21,504.0	22,419.7	23,374.2	24,430.1	25,563.0
Elimination manual reading expenses: Vehicles	0.0	0.0	344.2	977.9	1,739.6	2,617.6	3,249.6	3,494.2	3,647.4	3,811.5	3,976.0	4,159.0	4,340.4	4,524.6	4,725.5	4,935.0	5,146.2	5,364.3	5,610.0	5,864.8
Elimination manual reading expenses: Office, Reimbursed	0.0	0.0	81.0	225.9	394.6	582.9	710.4	749.9	768.5	788.3	807.3	829.0	849.4	869.2	891.2	913.7	935.4	957.2	982.7	1,008.6
Elimination manual reading expenses: Injuries, Damages	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elimination manual reading expenses: Training and Recruitment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Elimination manual reading expenses: Materials	0.0	0.0	43.3	120.8	211.0	311.7	379.9	401.0	411.0	421.6	431.8	443.4	454.3	464.9	476.6	488.7	500.3	511.9	525.6	539.4
Elimination manual reading expenses: Overtime	0.0	0.0	79.8	226.7	403.3	606.9	753.4	810.1	845.6	883.6	921.8	964.2	1,006.3	1,049.0	1,095.5	1,144.1	1,193.1	1,243.7	1,300.6	1,359.7
Avoided Expense of the Itron PP4 system - HW	0.0	0.0	0.0	0.0	0.0	0.0	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	4.9	5.0	5.1	5.3	5.4	5.5
Avoided Expense of the Itron PP4 system - O&M	0.0	0.4	3.5	7.0	10.7	15.4	16.0	16.7	17.3	18.0	18.7	19.4	20.2	21.0	21.8	22.6	23.5	24.4	25.4	26.4
Avoided Meter Read System Software Maintenance	0.0	0.0	0.0	0.0	35.0	72.6	75.5	78.4	81.5	84.7	88.0	91.4	95.0	98.7	102.5	106.5	110.7	115.0	119.5	124.1
Avoided Maintenance of IT Servers (Itron PP4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Related to the Field Meter Services Function																				
Reduction in F&MS expenses: Direct Labor	0.0	0.0	4,607.2	4,242.3	5,675.8	7,160.6	7,233.7	7,412.9	7,801.9	8,056.1	8,431.6	8,883.6	9,262.3	9,623.5	10,089.8	10,478.9	11,154.8	11,569.8	12,102.0	12,616.0
Reduction in F&MS expenses: Incentive	0.0	0.0	236.0	217.3	290.7	366.7	370.5	379.7	399.6	412.6	431.8	455.0	474.4	492.9	516.8	536.7	571.3	592.6	619.8	646.1
Reduction in F&MS expenses: Benefit and Pensions	0.0	0.0	3,523.9	3,244.7	4,341.2	5,476.9	5,532.7	5,669.8	5,967.3	6,161.7	6,449.0	6,794.7	7,084.3	7,360.6	7,717.2	8,014.8	8,531.8	8,849.2	9,256.3	9,649.4
Reduction in F&MS expenses: Vehicles	0.0	0.0	616.9	568.0	759.9	958.7	968.5	992.5	1,044.6	1,078.6	1,128.9	1,189.4	1,240.1	1,288.5	1,350.9	1,403.0	1,493.5	1,549.1	1,620.3	1,689.2
Reduction in F&MS expenses: Office, Reimbursed	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction in F&MS expenses: Injuries, Damages	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction in F&MS expenses: Other Premiums	0.0	0.0	434.7	400.2	535.5	675.6	682.5	699.4	736.1	760.1	795.5	838.1	873.9	908.0	951.9	988.7	1,052.4	1,091.6	1,141.8	1,190.3
Reduction in F&MS expenses: Materials	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reduction in F&MS expenses: Overtime	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMR: Avoided communication costs (MV90, SmartSync)	0.0	0.0	26.6	277.5	463.6	605.0	631.7	659.5	688.5	718.8	750.4	783.4	817.8	853.7	891.2	930.3	971.1	1,013.6	1,058.0	1,104.3
AMR: Avoided software maintenance (MV90, SmartSync)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Salvage Value of Replaced Meters	0.0	440.8	451.9	463.2	474.8	486.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Related to the Billing Function																				
Reduction in Billing expenses: Direct Labor	242.4	0.0	440.5	736.0	960.5	1,203.5	1,465.9	1,858.5	2,062.6	2,153.3	2,372.4	2,346.8	2,449.9	2,557.4	2,817.4	2,940.9	2,908.9	3,204.3	3,344.6	3,491.0
Reduction in Billing expenses: Benefit and Pensions	184.2	0.0	334.8	559.3	730.0	914.6	1,114.1	1,412.4	1,567.5	1,636.5	1,803.0	1,783.6	1,861.9	1,943.6	2,141.2	2,235.1	2,210.7	2,435.3	2,541.9	2,653.2
Reduction in Billing expenses: Overtime	38.5	0.0	69.3	115.2	149.6	186.6	226.2	285.3	315.1	327.4	359.0	353.5	367.3	381.6	418.4	434.7	428.0	469.3	487.6	506.6
Related to the Call Center Function																				
Reduction in Call Center expenses: Direct Labor (including P&B)	0.0	0.0	4.3	9.1	42.6	79.4	118.7	168.4	175.8	183.6	191.7	200.1	208.9	218.0	227.6	237.6	248.0	258.9	270.2	282.0
Related to the OMS Function																				
Reduced single lights-out trips	0.0	0.0	0.0	0.0	525.7	548.9	573.1	598.3	624.7	652.1	680.8	710.7	742.0	774.5	808.5	844.0	881.0	919.6	959.8	1,001.8
Improved outage restoration (reduction in storm overtime)	0.0	0.0	0.0	0.0	3,352.6	3,500.5	3,654.7	3,815.7	3,983.7	4,158.9	4,341.8	4,532.6	4,731.7	4,939.4	5,156.2	5,382.3	5,618.2	5,864.3	6,121.1	6,389.0
Subtotal, O&M Impacts	465.2	441.3	15,274.8	26,554.2	46,978.4	65,274.7	76,057.0	81,444.2	85,340.5	88,960.3	93,086.5	97,194.0	101,391.0	105,621.4	110,663.4	115,400.8	120,477.9	125,779.0	131,470.2	137,334.9
UTILITY: Items that Impact Capital Budgets (Avoided Capital Costs)																				
Avoided Handheld System Software Upgrade	0.0	306.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	358.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.1	0.0	0.0
Avoided IT Hardware purchases for AMR (MV90, SmartSync)	0.0	623.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	760.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	924.7	0.0	0.0
Subtotal, Capital Budget Impacts	0.0	929.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,118.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,344.8	0.0	0.0
UTILITY: Other Items																				
SAIDI/CAIDI Reduction (Customer Average Interruption Duration Index)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal, Other Items	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CUSTOMER BENEFITS																				
Reduction in consumption on inactives (CIM)	0.0	409.1	6,541.7	17,933.6	31,100.7	47,691.3	65,065.3	71,074.6	75,055.4	77,826.3	80,425.5	83,325.0	86,592.7	90,159.2	92,978.0	96,041.1	99,475.6	103,156.5	107,139.3	111,373.2
Reduction in UFE	0.0	0.0	4,206.4	11,294.1	20,521.7	32,980.5	47,612.4	53,658.6	56,999.5	58,727.6	60,627.6	62,388.4	64,526.5	66,951.8	68,303.9	69,852.0	71,762.4	73,869.0	76,243.0	78,812.1
Reduction in Net Bad Debt Expense (Remote Disconnect)	0.0	0.0	3,851.5	10,558.7	18,311.0	28,078.9	38,308.1	41,846.2	44,189.9	45,821.3	47,351.7	49,058.8	50,982.7	53,082.5	54,742.1	56,545.6	58,567.7	60,734.8	63,079.8	65,572.5
Subtotal, Customer Impacts	0.0	409.1	14,599.7	39,786.3	69,933.4	108,750.7	150,985.8	166,579.4	176,244.8	182,375.3	188,404.7	194,772.3	202,101.9	210,193.4	216,024.0	222,438.6	229,805.7	237,760.4	246,462.1	255,757.9

D.3 AMI Cost Details

AMI Costs	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Summary Results ($1000's)																				
Capital Items – Summary																				
Meters	-	22,438.3	156,992.2	162,072.4	164,199.7	201,114.2	2,815.4	2,871.7	2,929.1	2,987.7	3,047.5	3,108.4	3,170.6	3,234.0	3,298.7	3,364.7	3,432.0	3,500.6	3,570.6	3,642.0
Meters – Labor	-	5,215.9	39,515.8	42,230.0	43,877.0	55,255.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters – HW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters – SW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters – Other	-	17,222.4	117,476.4	119,842.4	120,322.8	145,858.4	2,815.4	2,871.7	2,929.1	2,987.7	3,047.5	3,108.4	3,170.6	3,234.0	3,298.7	3,364.7	3,432.0	3,500.6	3,570.6	3,642.0
Communication System	-	18,193.8	20,463.8	16,617.7	10,550.9	7,484.8	1,331.0	1,380.8	2,715.7	2,819.3	2,910.5	2,050.5	1,606.2	1,709.2	1,710.7	3,472.7	3,605.6	3,723.8	2,596.9	2,015.1
Comm Sys – Labor	-	1,732.9	1,800.5	1,870.7	647.9	-	57.0	59.3	61.6	64.0	66.5	69.1	71.8	74.6	77.5	80.5	83.6	86.9	90.3	93.8
Comm Sys – HW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comm Sys – SW	-	3,026.4	4,555.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comm Sys – Other	-	13,434.5	14,108.1	14,747.0	9,903.1	7,484.8	1,274.0	1,321.5	2,654.1	2,755.3	2,844.0	1,981.4	1,534.4	1,634.6	1,633.3	3,392.2	3,522.0	3,636.9	2,506.6	1,921.3
Information Technology Applications and Operations	1,250.0	17,910.0	17,541.2	8,516.2	10,655.1	4,273.5	1,757.0	4,177.1	1,058.2	444.4	4,400.4	1,122.9	471.6	4,704.1	1,156.6	500.5	4,992.0	1,264.6	493.2	5,297.5
IT – Labor	1,250.0	10,987.4	11,608.7	6,691.7	3,117.4	1,922.2	1,368.1	-	-	-	-	-	-	-	-	-	-	-	-	-
IT – HW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IT – SW	-	2,748.0	4,401.2	1,262.5	1,881.3	1,266.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IT – Other	-	4,174.6	1,531.3	561.9	5,656.5	1,084.5	388.9	4,177.1	1,058.2	444.4	4,400.4	1,122.9	471.6	4,704.1	1,156.6	500.5	4,992.0	1,264.6	493.2	5,297.5
Management and Other Costs	2,495.5	10,560.5	8,390.0	8,004.3	7,772.6	7,800.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mgmt / Other – Labor	-	5,402.7	3,650.3	3,723.3	3,797.8	3,873.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mgmt / Other – HW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mgmt / Other – SW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mgmt / Other – Other	2,495.5	5,157.9	4,739.6	4,280.9	3,974.8	3,926.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal, Capital	3,745.5	69,102.6	203,387.2	195,210.5	193,178.4	220,672.8	5,903.4	8,429.6	6,703.0	6,251.5	10,358.4	6,281.8	5,248.4	9,647.3	6,166.0	7,337.9	12,029.5	8,489.0	6,660.7	10,954.7
O&M Items – Summary																				
Meters and Modules	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters – Labor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters – Materials	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters – Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Communication System	-	2,333.0	4,739.3	5,428.7	6,056.1	7,930.6	8,261.8	8,443.1	8,629.8	8,822.2	9,020.4	9,224.7	9,435.3	9,652.3	9,876.0	10,106.7	10,344.6	10,589.9	10,843.0	11,104.1
Comm Sys – Labor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comm Sys – Materials	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Comm Sys – Services	-	2,333.0	4,739.3	5,428.7	6,056.1	7,930.6	8,261.8	8,443.1	8,629.8	8,822.2	9,020.4	9,224.7	9,435.3	9,652.3	9,876.0	10,106.7	10,344.6	10,589.9	10,843.0	11,104.1
Information Technology Applications and Operations	5,108.2	6,981.7	9,122.9	10,594.5	13,606.7	15,238.7	16,518.5	15,838.5	19,154.9	17,062.0	19,175.4	18,381.4	19,079.4	19,804.2	20,556.9	21,338.6	22,150.3	22,993.3	23,868.8	24,778.0
IT – Labor	867.5	1,481.1	2,150.1	2,869.0	3,928.7	4,736.8	4,289.7	4,457.0	4,630.8	4,811.4	4,999.1	5,194.1	5,396.6	5,607.1	5,825.8	6,053.0	6,289.0	6,534.3	6,789.2	7,053.9
IT – Materials	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IT – Services	4,240.7	5,500.6	6,972.9	7,725.5	9,678.0	10,501.9	12,228.8	11,381.5	14,524.1	12,250.6	14,176.3	13,187.4	13,682.8	14,197.1	14,731.2	15,285.6	15,861.3	16,459.0	17,079.6	17,724.0
Management and Other Costs	699.0	11,713.7	14,032.4	13,932.8	14,559.2	14,940.2	5,132.9	5,333.1	5,541.0	5,757.1	5,981.7	6,215.0	6,457.3	6,709.2	6,970.8	7,242.7	7,525.2	7,818.6	8,123.6	8,440.4
Mgmt / Other – Labor	699.0	11,222.4	13,011.3	12,606.6	13,181.4	13,508.6	3,645.5	3,787.6	3,935.4	4,088.8	4,248.3	4,414.0	4,586.1	4,765.0	4,950.8	5,143.9	5,344.5	5,553.0	5,769.5	5,994.5
Mgmt / Other – Materials	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mgmt / Other – Services	-	491.4	1,021.1	1,326.1	1,377.8	1,431.6	1,487.4	1,545.4	1,605.7	1,668.3	1,733.4	1,801.0	1,871.2	1,944.2	2,020.0	2,098.8	2,180.6	2,265.7	2,354.0	2,445.9
Subtotal, O&M	5,807.2	21,028.4	27,894.6	29,956.0	34,222.0	38,109.6	29,913.2	29,614.6	33,325.8	31,641.4	34,177.5	33,821.1	34,972.0	36,165.7	37,403.8	38,688.0	40,020.1	41,401.9	42,835.4	44,322.4
Grand Total, Capital + O&M	***9,552.7***	***90,131.0***	***231,281.9***	***225,166.5***	***227,400.4***	***258,782.4***	***35,816.6***	***38,044.2***	***40,028.7***	***37,892.9***	***44,535.8***	***40,102.9***	***40,220.4***	***45,813.0***	***43,569.8***	***46,025.9***	***52,049.6***	***49,890.9***	***49,496.1***	***55,277.1***

D.4 Deployment (5 Year Plan)

Deployment Details	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Populations (End of Period Values)																				
Total # Meter Population (end of period) ("As Is" and "To Be")	4,062,022	4,082,242	4,102,462	4,122,682	4,142,902	4,163,122	4,183,342	4,203,562	4,223,782	4,244,002	4,264,222	4,284,442	4,304,662	4,324,882	4,345,102	4,365,322	4,385,542	4,405,762	4,425,982	4,446,202
Total # EM Meters (end of period) ("To Be") - including RRTP & IDR	3,932,022	3,820,099	2,920,993	2,004,227	1,094,777	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
# **Mass** SG Meters (end of period)	130,000	262,143	1,181,469	2,118,455	3,048,125	3,957,074	3,976,286	3,995,498	4,014,710	4,033,922	4,053,134	4,072,346	4,091,558	4,110,770	4,129,982	4,149,194	4,168,406	4,187,618	4,206,830	4,226,042
# **Rural** SG Meters (end of period)	-	-	-	-	-	103,024	103,528	104,032	104,536	105,040	105,544	106,048	106,552	107,056	107,560	108,064	108,568	109,072	109,576	110,080
# **Urban** SG Meters (end of period)	-	-	-	-	-	103,024	103,528	104,032	104,536	105,040	105,544	106,048	106,552	107,056	107,560	108,064	108,568	109,072	109,576	110,080
Total # SG Meters (end of period)	130,000	262,143	1,181,469	2,118,455	3,048,125	4,163,122	4,183,342	4,203,562	4,223,782	4,244,002	4,264,222	4,284,442	4,304,662	4,324,882	4,345,102	4,365,322	4,385,542	4,405,762	4,425,982	4,446,202
% of SG Meters (end of period)	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Electric Additions	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220
Current System Read Performance																				
# Electric Reads (seasonality adjustment, "As Is")	40,714,133	40,917,344	41,120,555	41,323,766	41,526,977	41,730,188	41,933,399	42,136,610	42,339,821	42,543,032	42,746,243	42,949,454	43,152,665	43,355,876	43,559,087	43,762,298	43,965,509	44,168,720	44,371,931	44,575,142
# Electric Reads (seasonality adjustment, "To Be")	39,424,567	39,445,281	33,548,747	24,333,785	15,154,358	4,873,635	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EM Replacements due to Failures																				
Failures: Electric EM Failures Under the "As Is" Scenario	32,426	32,579	32,746	32,910	33,066	33,233	33,396	33,549	33,716	33,882	34,035	34,204	34,366	34,519	34,690	34,852	35,005	35,174	35,335	35,490
Failures: Residual Electric EM Failures Replaced as EM	31,386	24,043	1,622	1,632	1,632	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Failures: Electric EM Failures Avoided	1,040	8,536	31,124	31,278	31,434	33,233	33,396	33,549	33,716	33,882	34,035	34,204	34,366	34,519	34,690	34,852	35,005	35,174	35,335	35,490
Failures: Electric EM Failures Replaced as SG	-	7,340	25,114	17,774	10,458	3,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EM Additions, or Avoided EM Additions, Associated with Growth																				
Growth: Electric EM Growth Additions Under the "As Is" Scenario	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220
Growth: Residual Electric EM Growth under the "To Be" Scenario	20,220	15,417	1,008	1,008	1,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Growth: Electric EM Growth Avoided (Difference, As Is and To Be)	-	4,803	19,212	19,212	19,212	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220
EM Electric Meters Remaining (end of year) ("To Be")	3,932,022	3,820,099	2,920,993	2,004,227	1,094,777	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Quantity EM and AMR Electric Reads (per year) ("To Be")	47,073,054	47,071,345	40,077,296	29,085,644	18,132,065	5,881,110	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI Smart Meter Devices (Electric)																				
SG Planned Deployment (Pilot + Core)	130,000	120,000	875,000	900,000	900,000	1,090,857	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SG Planned Deployment (Core Only)	-	120,000	875,000	900,000	900,000	1,090,857	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Growth Electric Meters (installed as SG)	-	4,803	19,212	19,212	19,212	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220
Total SG Deployed (not counting SG failures) (Includes Pilot)	130,000	132,143	919,326	936,986	929,670	1,114,997	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220	20,220
Cumulative SG Installations (not counting SG failures) [Includes Pilot]	130,000	262,143	1,181,469	2,118,455	3,048,125	4,163,122	4,183,342	4,203,562	4,223,782	4,244,002	4,264,222	4,284,442	4,304,662	4,324,882	4,345,102	4,365,322	4,385,542	4,405,762	4,425,982	4,446,202
AMI Failure Related Replacement Work																				
Failed SG Meters (for installation, warranty replacement, or replaceme	650	752	3,767	8,448	13,113	18,395	20,870	20,971	21,073	21,174	21,275	21,376	21,477	21,578	21,679	21,780	21,881	21,982	22,084	22,185
Failed SG Meters Outside Warranty	-	-	-	-	-	648	2,211	7,475	12,205	16,849	20,559	20,948	21,044	21,140	21,240	21,356	21,452	21,548	21,644	21,748
AMI Network Services and Equipment Provisioning																				
Repeaters (Mass, Rural, High Rise, Growth)	-	1,968	1,968	1,968	656	-	54	54	54	54	54	54	54	54	54	54	54	54	54	54
Takeout Pts (Mass, Rural, High Rise, Growth)	-	423	423	423	141	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Total # Devices Installed (Mass, Rural, High Rise, Growth)	-	2,391	2,391	2,391	797	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65
Failures, Repeaters	-	98	197	295	328	328	331	333	336	339	342	344	347	350	352	355	358	360	363	366
Failures, Takeouts	-	21	42	63	71	71	71	72	72	73	73	74	74	75	75	76	77	77	78	78
Battery Replacements	-	-	-	-	-	-	-	-	2,391	2,391	2,391	797	-	65	-	2,391	2,391	2,391	797	-

D.5 Net Customer Impact

	Sum, 20 yrs 2011-2030	1 2011	2 2012	3 2013	4 2014	5 2015	6 2016	7 2017	8 2018	9 2019	10 2020	11 2021	12 2022	13 2023	14 2024	15 2025	16 2026	17 2027	18 2028	19 2029	20 2030
Summary Results -- Net Customer Impact -- (nominal $1,000s)																					
O&M Benefits	1,625,209.7	465.2	441.3	15,274.8	26,554.2	46,978.4	65,274.7	76,057.0	81,444.2	85,340.5	88,960.3	93,086.5	97,194.0	101,391.0	105,621.4	110,663.4	115,400.8	120,477.9	125,779.0	131,470.2	137,334.9
Total AMI O&M Savings	1,625,209.7	465.2	441.3	15,274.8	26,554.2	46,978.4	65,274.7	76,057.0	81,444.2	85,340.5	88,960.3	93,086.5	97,194.0	101,391.0	105,621.4	110,663.4	115,400.8	120,477.9	125,779.0	131,470.2	137,334.9
O&M Expenses																					
Meters and Modules	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Communication System	(160,841.6)	0.0	(2,333.0)	(4,739.3)	(5,428.7)	(6,056.1)	(7,930.6)	(8,261.8)	(8,443.1)	(8,629.8)	(8,822.2)	(9,020.4)	(9,224.7)	(9,435.3)	(9,652.3)	(9,876.0)	(10,106.7)	(10,344.6)	(10,589.9)	(10,843.0)	(11,104.1)
Information Technology Applications and Operations	(341,353.2)	(5,108.2)	(6,981.7)	(9,122.9)	(10,594.5)	(13,606.7)	(15,238.7)	(16,518.5)	(15,838.5)	(19,154.9)	(17,062.0)	(19,175.4)	(18,381.4)	(19,079.4)	(19,804.2)	(20,556.9)	(21,338.6)	(22,150.3)	(22,993.3)	(23,868.8)	(24,778.0)
Management and Other Costs	(163,125.9)	(699.0)	(11,713.7)	(14,032.4)	(13,932.8)	(14,559.2)	(14,940.2)	(5,132.9)	(5,333.1)	(5,541.0)	(5,757.1)	(5,981.7)	(6,215.0)	(6,457.3)	(6,709.2)	(6,970.8)	(7,242.7)	(7,525.2)	(7,818.6)	(8,123.6)	(8,440.4)
Total AMI O&M Expenses	(665,320.7)	(5,807.2)	(21,028.4)	(27,894.6)	(29,956.0)	(34,222.0)	(38,109.6)	(29,913.2)	(29,614.6)	(33,325.8)	(31,641.4)	(34,177.5)	(33,821.1)	(34,972.0)	(36,165.7)	(37,403.8)	(38,688.0)	(40,020.1)	(41,401.9)	(42,835.4)	(44,322.4)
Depreciation, Taxes, and Total Cost to Customers (pre UFE, CIM and Bad Debt adjusted)																					
Net Change in Operation and Maintenance Expenses	959,889.0	(5,342.0)	(20,587.1)	(12,619.8)	(3,401.8)	12,756.3	27,165.1	46,143.8	51,829.6	52,014.7	57,318.9	58,909.0	63,372.9	66,419.0	69,455.8	73,259.6	76,712.8	80,457.8	84,377.1	88,634.9	93,012.5
Net Change in Book Depreciation	(934,306.2)	(125.9)	(2,751.9)	(16,028.1)	(33,582.9)	(48,565.8)	(64,509.5)	(68,319.3)	(63,106.4)	(60,989.9)	(58,268.5)	(56,564.0)	(57,219.6)	(56,899.9)	(57,125.4)	(58,529.2)	(58,236.6)	(57,087.0)	(51,072.6)	(38,548.8)	(26,774.8)
Net Change in Taxes, Other than Income Taxes	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Change in Income Taxes	(180,619.0)	(114.4)	(2,159.4)	(8,007.8)	(12,841.5)	(17,049.0)	(21,655.0)	(19,206.4)	(17,120.0)	(15,139.6)	(13,225.7)	(11,532.0)	(9,718.6)	(7,990.6)	(6,586.7)	(5,224.8)	(4,110.8)	(3,280.3)	(2,405.2)	(1,761.6)	(1,489.6)
Net Change in Return	(464,879.2)	(294.3)	(5,557.9)	(20,610.6)	(33,051.6)	(43,880.8)	(55,735.9)	(49,433.5)	(44,063.6)	(38,966.6)	(34,040.6)	(29,681.3)	(25,013.8)	(20,566.4)	(16,952.9)	(13,447.7)	(10,580.4)	(8,443.0)	(6,190.4)	(4,534.0)	(3,833.9)
Accelerated Recovery of Retired Meters	(20.6)	0.8	2.1	9.9	13.0	14.0	5.2	1.3	1.1	1.0	0.8	0.4	0.2	(6.9)	(9.6)	(10.9)	(10.8)	(9.6)	(8.5)	(7.6)	(6.5)
Total Cost to Customers (Before UFE, CIM and Bad Debt Expense Related E	(619,935.9)	(5,875.8)	(31,054.2)	(57,256.4)	(82,864.9)	(96,725.2)	(114,730.0)	(90,814.1)	(72,459.2)	(63,080.4)	(48,215.1)	(38,867.9)	(28,578.9)	(19,045.0)	(11,218.9)	(3,953.1)	3,774.3	11,637.8	24,700.4	43,782.9	60,907.7
UFE, CIM and Bad Debt Expense-Related Benefits																					
Collection of Delivery Service Revenues due to Changes to UFE and CIM	564,213.0	0.0	154.6	3,585.3	10,181.5	16,267.9	22,701.1	27,084.5	27,137.3	28,158.9	29,757.1	30,842.2	32,585.1	34,321.2	36,079.9	38,308.6	40,613.4	42,938.4	45,342.1	47,802.9	50,350.9
Reduction in Energy Purchase Power Costs Due to Changes to UFE and CIM	707,508.0	0.0	0.0	2,882.3	7,664.1	14,226.5	23,327.2	34,442.4	39,272.3	41,807.4	42,974.7	44,348.5	45,522.5	46,999.1	48,702.5	49,484.1	50,412.1	51,627.4	52,989.0	54,556.7	56,268.9
Collection in Energy Revenues Due to Changes to UFE and CIM	1,050,980.6	0.0	254.5	4,280.5	11,382.0	21,127.9	34,643.5	51,150.8	58,323.6	62,088.6	63,822.1	65,862.4	67,605.8	69,798.8	72,328.5	73,489.2	74,867.5	76,672.3	78,694.4	81,022.7	83,565.5
Reduction in Bad Debt Expenses	790,684.0	0.0	0.0	3,851.5	10,558.7	18,311.0	28,078.9	38,308.1	41,846.2	44,189.9	45,821.3	47,351.7	49,058.8	50,982.7	53,082.5	54,742.1	56,545.6	58,567.7	60,734.8	63,079.8	65,572.5
Total Additional Benefits	3,113,385.6	0.0	409.1	14,599.7	39,786.3	69,933.4	108,750.7	150,985.8	166,579.4	176,244.8	182,375.3	188,404.7	194,772.3	202,101.9	210,193.4	216,024.0	222,438.6	229,805.7	237,760.4	246,462.1	255,757.9
Net Customer Impact (Change in Customer Costs)																					
Net Impact to Customer Costs (Negative = Better for Customer)	2,493,449.7	(5,875.8)	(30,645.1)	(42,656.7)	(43,078.6)	(26,791.8)	(5,979.4)	60,171.7	94,120.2	113,164.4	134,160.2	149,536.8	166,193.4	183,057.0	198,974.5	212,071.0	226,212.9	241,443.5	262,460.8	290,245.0	316,665.6
Cumulative Net Customer Impact (Change in Customer Costs)																					
Cumulative Net Impact to Customer Costs	2,493,449.7	(5,875.8)	(36,520.9)	(79,177.6)	(122,256.1)	(149,047.9)	(155,027.3)	(94,855.6)	(735.4)	112,429.0	246,589.2	396,126.0	562,319.4	745,376.4	944,350.9	1,156,421.9	1,382,634.8	1,624,078.3	1,886,539.1	2,176,784.1	2,493,449.7
Net Present Value of Net Customer Impact																					
Cumulative Net Present Value (NPV)	1,295,848.1	(5,635.2)	(33,821.7)	(71,449.5)	(107,893.3)	(129,630.6)	(134,283.3)	(89,380.1)	(22,019.2)	55,654.7	143,968.8	238,373.8	338,997.7	445,293.1	556,099.9	669,363.6	785,232.6	903,838.5	1,027,488.9	1,158,629.4	1,295,848.1

Appendix E: Cost Assumptions

E.1 General Inputs and Assumptions

The purpose of this Appendix is to describe the data inputs and assumptions related to the cost components of the AMI / Smart Meter cost-benefit evaluation.

Terms of Reference and General Assumptions

- The “evaluation” refers to the entirety of the Black & Veatch analysis.
- “Cases” refer to the specific comparisons of distinct scenarios.
- “Scenarios” refer to views of the future either with or without the influence of smart metering automation — “As-Is” and “To-Be”
- The comparison of two Scenarios leads to a Case.
- The “evaluation period” refers to the period 2011 – 2030, the 20 year evaluation period under scrutiny.
- “Smart Meters” and “AMI” meters are used interchangeably.

Scenarios

- The evaluation is based on two scenarios —The “As Is” and the “To Be” scenarios.
- The “As Is” scenario is the estimate of ComEd’s meter population, activities, FTE requirements, and costs for operating the current meter reading system and without the benefit of automation through the evaluation period
- The “To Be” scenario is the estimate of ComEd’s meter population, activities, FTE requirements and costs and avoided costs for building and operating the AMI or smart meter metering system.

Cases

- The comparison of the “As Is” and “To Be” scenarios yields a “Case”. There are two cases that have been developed:
- The five (5) year deployment case assumes that ComEd deploys the smart meter system starting in 2012 and completes it in 2016.
- The ten (10) year deployment case assumes that ComEd deploys the smart meter system starting in late 2011 and completes it in 2020.
- See Appendix B for a visual representation of meter populations under each Case.
- The evaluation scenarios and cases are driven by meter populations (or meter counts), not customer counts or customer locations.
- A Start Year is defined as 2011, and as year no. 1 for both Cases. The model analysis period is 30 years (2011 – 2040).
- The 30 year analysis duration is distinct from the evaluation period selected by ComEd and Black & Veatch. The analysis duration is assumed to be 20 years (2011 – 2030). 30 years is structured in the model for convenience.

Meter Population and Growth Assumptions

- Meter growth is specified at 0.5% per year. This value is not a compounding value. Given ComEd’s current meter population, growth is ~ 20,000 meters per year. This value is applied uniformly for each year under the evaluation.

- Growth is assumed to occur uniformly throughout the ComEd service territory.
- The meter population plus meter growth is greater than the total number of ComEd customers served.
- The evaluation assumes that ComEd's meter population is composed of the following segments: 3,841,802 meters are in the "mass" deployment area, 100,000 are in the low density rural area and 100,000 are in the meter high rise environments.
- New Business Sets & New Business Change Meter Orders (CMO) will continue to increase annually consistent with meter growth. These activities are included in the growth volume.
- The first year of growth adjustment is 2012.

E.2 Financial Inputs and Assumptions

General Financial Inputs and Assumptions

Black & Veatch received the following inputs from the ComEd Finance department to be used in the evaluation:

- The evaluation is structured using nominal dollars, with a base year of 2011 = $1.00.87
- ComEd Return on equity - 10.3%
- ComEd Cost of debt - 6.5%
- ComEd Percent debt - 55%
- ComEd Percent equity - 45%
- The ComEd Marginal Tax Rate (State and Federal combined) assumed at 40%
- Illinois Sales Tax Rate: 5.625% for AMI meters (this is an adjustment from the 6.25% state tax rate to reflect the assumption that there will be an approximate 10% reduction in sales tax revenue because of the enterprise zone savings across the state); 6.250% for other material/equipment
- ComEd Marginal Tax Rate (Federal and State) assumed at 39.75%
- A Discount Rate of 4.27% used in the evaluation (this is the 20-year Treasury)
- The evaluation model can assume (based on user selection) whether meters (smart meters or existing Electro-Mechanical meters) become obsolete and require "refresh" or replacement. This is a fundamental assumption regarding the physical plant and the requirements to upgrade it over time. At this time, ComEd has elected to remove this assumption from both the "As Is" and the "To Be" scenarios. In effect, arguments about the nature, rate and scope of meter replacement requirements once meters reach their end-of-life are not included and effectively deferred from this evaluation.

Energy Cost Assumptions

- The evaluation is influenced by the cost the ComEd customer pays for electricity services (both the power purchase cost component and the delivery charge). The evaluation assumes that the 2011 weighted average energy supply (fully bundled) rate is 12.05 cents per kWh. This reflects all energy cost components (distribution components and power purchase cost).
- The evaluation considers the distribution component and the power purchase cost component separately.

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[87] One project risk relates to currency value fluctuations to the degree that equipment, supplies and services are dependent on foreign sources of supply. No analysis of the currency risk is included. The evaluation includes factors for general price escalation.

- For purposes of the evaluation, Black & Veatch is treating the "Electricity Supply Services" as the Energy component, and the "Delivery Services" and "Taxes and Other" as the Delivery component.
- ComEd has provided an analysis of the changes to energy prices (both the energy and distribution components) over time. This analysis is presented in Appendix B, and includes the year-by-year change in the energy and distribution cost components. These values are used in the evaluation to drive the year-by-year adjustment in cost components.

Evaluation Time Horizon

- Analysis structure, time horizon —The analysis assumes a start date for program activities in year 2011. For evaluation purposes, it assumes a horizon of 20 years, or the end of 2030. As a practical matter, since expenditures start mostly in 2012, costs and benefits occur over a 19+ year period using this structure.
- Terminal or On-Going Value—No on-going or terminal value argument is used in the analysis of the business case(s). In outer years beyond 20, many pricing and cost assumptions developed today are speculative.

Escalation (Services/Labor, Materials, Energy and Delivery Costs)

- Escalation—The yearly change in prices and costs (escalation) result from general price inflation in the economy as well as from estimates of real price changes from suppliers and others.
- Escalation is a compounded value. If a product costs $100 in year 1, and escalation is 2%, then the product cost is:
    - $100 in year one
    - $100 x 1.02 = $102.00 in year two
    - $100 x 1.02^2 = $104.04 in year three
- Materials — An escalation rate is used for "materials" to reflect changes in the prices and costs of equipment like computer servers and RF network devices. A value of 2.0% is used.
- Services/Labor—A rate is used to reflect changes in prices and costs of labor inputs. A value of 3.9% per annum is used. This reflects ComEd's historical experience with managing its labor force. It is expected to continue over the evaluation time frame.
- Energy and Delivery Costs — See above.
- 2012 is the first year of adjustment.

Incentives and Pension and Benefits

- The model uses specific rates and values to calculate the benefits of avoided Incentive and Pension and Benefit costs for the Meter Reading and Field and Meter Services.
- For estimated FTE reductions in the Billing and Call Center areas, the general ComEd-wide standard rate for Incentives and Pension and Benefits are applied.

Pilot System Costs

ComEd has deployed approximately 131,000 smart meters as part of its pilot program. The costs associated with building and operating this pilot are not included in the evaluation. They are assumed to be sunk. The *future* costs of operating the pilot system are included in the evaluation. The *future* avoided costs (e.g., benefits) of operating the pilot system are included in the evaluation.

Book and Tax Depreciation Schedules

Depreciation impacts the ComEd business cases in several ways. Depreciation (new investment) and avoided depreciation (avoided investment) are computed in the evaluation. Depreciation is modeled for regulatory recovery purposes (straight line "book" depreciation) and for cash tax purposes (accelerated, or MACRS)[88].

Each new cost and each avoided cost (e.g., benefit) is delineated for its type (O&M or capital). For capital expenses, various depreciation schedules are chosen:

- IT Hardware
    - Book Depreciation = 5 years
    - Tax Depreciation (MACR) = 5 years
- IT Software
    - Book Depreciation = 5 years
    - Tax Depreciation (MACR) = 3 years
- AMI Meters and Other Communication
    - Book Depreciation = 15 years
    - Tax Depreciation (MACR) = 10 years (double declining)
- Analog Meters
    - Book Depreciation = 30 years
    - Tax Depreciation (MACR) = 20 years

E.3 Deployment Inputs and Assumptions

ComEd's smart metering deployment assumes four segments or meter populations. These segments reflect both a geographic segmentation, as well as network-solution segmentation. Given the unique telecommunication challenges of these individual segments, and specifically the High Rise and Rural segments, each of these segments will require a different level of AMI telecommunications infrastructure, and therefore each will have a different AMI cost profile. As such, it is only appropriate to then model the costs for each of these independently and aggregate them within the business case.

- Rural Segment—ComEd has an estimated 100,000 meters in the rural geographic areas of its service territory. These 100,000 meters are deployed in the last year of the five year and ten year "To Be" deployment scenario. See Appendix B for a visual depiction of meter deployment quantities by year.
- High Rise Urban Segment—ComEd has approximately 100,000 in a high density urban segment. These meters represent a special class of meter solution challenges due to the demanding RF and power-line environments of these meters. Similar to the deployment of the meters in the Rural segment, these 100,000 High Rise meters are deployed in the last year of the five year and ten year "To Be" deployment scenario.
- Mass Deployment Segment—ComEd has approximately 3,841,802 meters in its core (aka mass) meter region (excluding Rural and High Rise). These meters are deployed throughout the five-year period (in the case of the five year deployment "To Be" scenario).
- Pilot segment—At the start of "mass deployment", ComEd will have deployed 131,000 AMI Pilot meters in the pilot region.

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[88] MACRS stands for Modified Accelerated Cost Recovery System.

Five Year Deployment Plan

As part of its deployment planning, ComEd has identified the deployment order, by operations center, that it would execute against as part of a five year deployment plan. Table E.1 lists the operations centers that would be deployed, with AMI meters, for each year of the five year deployment scenario. The order of deployment corresponds to the relative expected value in benefits realized.

Table E.1 Five-year Deployment by Operations Center

Year	Operations Centers
2012	Balance of Maywood
2013	Chicago South, Crestwood, UPA
2014	Chicago North, Rockford
2015	Aurora, Bolingbrook, Crystal Lake, Elgin, Glenbard, Joliet
2016	Libertyville, Mt. Prospect, Skokie, Rural Offices (DeKalb, Dixon, Freeport, Streator)

The five-year deployment scenario assumes the following:

- Actual project work must begin January 1, 2012 to support meter deployment starting October 1, 2012. Lead times are required by ComEd IT and the Business Operations group overseeing design, planning, deployment and operations.
- ComEd IT will need to expand the Pilot system infrastructure, modify certain processes based on Pilot learnings, and potentially replace the currently utilized MDMS system.
- The Business Operations will need to develop the overall project plan, redesign and test business processes, set up cross dock operation and develop tools/controls for meter deployment and billing.
- Geographical deployment by office represented in Table E.1 above is primarily based on Benefits associated with the socialized costs from consumption on inactive accounts and bad debt expense.
- By year four, secondary considerations for deployment include office proximity to already deployed offices.
- Rural offices and downtown high rises may require different AMI technologies or the use of more AMI network infrastructure and better left to deployment in the last 12 months of the deployment duration.

Ten-year Deployment Plan

A ten year deployment plan is also evaluated in consideration of a pending state Legislative bill receiving approval in the summer of 2011. The ten year deployment scenario assumes the following:

- July 1, 2011 Legislative approval is provided.
- Smart meter installations are to begin September 2011, earlier than the five year deployment scenario which begins meter deployment in Oct 2012.
- 280,000 smart meters installed between September, 2011 and May, 2012. This initial “early” deployment represents the number of additional meters (incremental to the 131k pilot meters), that ComEd’s IT infrastructure can support before implementing additional hardware and software to support the full AMI deployment.

- A 2-month hiatus in installing AMI meters may be required from June - July 2012 to allow sufficient time for IT to implement full scale infrastructure and system enhancements.
- Similar to the five-year plan, 100,000 rural meters and 100,000 high rise meters are planned for installation in the last 12 months of the deployment schedule.

Additional Deployment Assumptions (Five and Ten-year Deployments)

The following deployment inputs and assumptions are independent of the deployment duration, and therefore apply to both the five-year and ten-year deployment plans.

- The five-year and ten-year deployment scenarios could potentially impact the number of Regulatory "periodic inspection" field trips ComEd must perform. It is possible that the smart meter installation work could help to satisfy or achieve the required periodic inspection. However, the evaluation does NOT assume any benefits from reduced field trips, during deployment, due to having the AMI Meter install also satisfy regulatory activity requirements.
- For the five-year deployment scenario, the evaluation assumes that there is no avoidance of the periodic inspection requirement.
- Implicit in model, there are no changes in Capitalized labor within F&MS going from the "As-Is" to the "To-Be" scenario throughout the evaluation period. While there is a change in the mix of field activities, there is no change in the estimated Capital labor.
- Current Electro-Mechanical meter (non-AMI) failure rate is 0.8% and is based on actual historical volumes. This is approximately 32,000 meters annually. This number is assumed to be constant throughout the evaluation period.
- It is assumed that Smart Meters will have a failure rate of 0.5% per year. Additionally, there is an assumed failure rate of 0.5% on the Network Interface Cards (NIC). Aggregated together, the business case assumes a total failure rate of 1.0% for Smart Meters and NICs. This rate will be constant through the five-year or ten-year deployment period. It remains constant, also, throughout the 20-year evaluation term.
- A warranty period is assumed (five years, or 60 months). The warranty is assumed as a feature that is provided by the meter manufacturer, and is included in the meter price. It is assumed to cover the NIC. This warranty covers the cost to ComEd of replacing the failed Smart Meter. It does not cover field replacement costs (although this may be subject to negotiation).
- The evaluation assumes that RF field network devices fail at a rate of 5% annually.

High Rise Segment Assumptions

Mentioned earlier, the driver in separating the different meter segments or populations, specifically the High Rise and Rural geographic areas, is due to the fact that there will be varying AMI infrastructure requirements and thus a different cost profile for each. Furthermore, while it is assumed that the same AMI technology can effectively support each of these segments, it is assumed that an increased number of AMI components (specifically APs), repeaters, and/or external antennas) will be required in the High Rise and Rural communities to achieve and support ongoing AMI telecommunications.

The following assumptions apply to the High Rise meter population, and were modeled accordingly to determine the cost.

- 100,000 meters—100% are supported by the same AMI network that is assumed to be deployed across the rest of ComEd's meters.
- 4,083 meters in High Rise area will require external antennae.
- $500 per meter to install external antennas.
- 431 buildings in High Rise area will require an Access Point on each building.
- $500 per building for monthly AP maintenance fee.

RF "Un-Friendly" Meters

- Based on pilot learnings, there are an estimated 9,975 meters outside of High Rise area that will have RF "challenges" and will thus require an external antennae for AMI communications.
- $500 per meter to install external antennas.

Rural Segment Assumptions

The following assumptions apply specifically to the Rural meter population, and were modeled accordingly to determine the cost.

- Based on ComEd's geographic work area analysis, meter count = 100,000 meters.
- 500 meters per AP.
- 25 Relays per AP.

Deployment of RF Field Network Devices

- The evaluation includes assumptions about the percentage of total required network devices by year for the deployment cycle. During the deployment cycle, 100% of the required field network devices will be deployed.
- The evaluation makes no distinction in deployment between the five-year and ten-year scenarios. It also assumes that the RF communication network is fully deployed at the end of five years in either case.
- Additionally, the evaluation assumes that RF Communication devices (APs, repeaters, etc.) are deployed in equal proportion in each period (year).
- Once deployed, the model assumes that there will incremental additional field network devices over the course of the remaining period (2017 - 2040) to account for overall system growth. The evaluation assumes that an additional 20% of RF devices are added to the network over time. These are evenly distributed over the post-deployment period. (2017 – 2040).

The evaluation takes as inputs the factors listed below. The number of RF communication devices (access points and repeaters) is based on ComEd-provided estimates based on ComEd Pilot experiences.

Table E.2 Count of Access Points and Repeaters by Meter Segment

Item	Count
Access Points for Mass Deployment	781
Repeaters, for Mass Deployment	1,562
Access Points for Rural Deployment	200
Repeaters, for Rural Mass Deployment	5,000
Access Points for High Rise Deployment	431
Repeater for High Rise Segment	0

- The evaluation assumes 5.0% failure rate of field network devices each year, requiring a field visit.
- The evaluation assumes that each device requires a battery, and that the approximate life of the battery is seven years. For the devices installed in year one, there will be a field visit in year eight to replace the battery. Year two devices, year nine field visit, etc.

E.4 AMI Meter and Installation Costs

AMI Meter Pricing

Meter pricing is assumed as $122.78 per Smart Meter. This is a fully weighted average meter price (all forms, single and poly-phase). This price excludes sales tax and overheads. It includes warranty (60 months assumed) and shipping and handling. This is a 2011 price. Escalation is not applied as it is assumed that during the installation period of five years the price is subject to contract without adjustment.

AMI Meter Installation Pricing

The installation of the Smart Meter is assumed to be $40.48 / meter. This is a 2011 rate and is subject to escalation. This value is a fully burdened and average per meter cost for installation work for all of ComEd's meter plant. The following items are assumed to be included in this per meter cost factor:

The evaluation assumes that any combinations of contractors or ComEd employees will provide a comprehensive set of services required to carry out the smart meter field installation work. ComEd is estimating that this work, when estimated on a per meter basis (and encompassing all forms and meter types), includes the following activities:

- Contractor bonding requirements.
- Satisfying ComEd's diversity-in-sourcing requirements.
- Work order management system provisioning and inventory control system (handling of daily batch receipt of new installation orders and daily transmission of completed orders; inventory control procedures and work flows with regards to receipt, storage and transfer of utility's metering assets). Security, backup, disaster recovery for this system.
- Provisioning of the meter installation-related data management system including all computer hardware and software; ensuring proper configuration and interface of the system to the utility meter data management, work order management system, and asset management systems

- Provisioning of all personal protective equipment, computers, tools, equipment, offices, warehouses, vehicles, communications equipment (e.g., cell phones, radios), etc.
- Customer call center operations and management (in relation to meter installation, not billing disputes and other inquires); appointment scheduling process; door hangers; customer complaint interface and resolution.
- Meter sample testing, provisioning; initial warranty interface (for warranty issues during the period of the meter field installation work).
- The field installation work itself (including site safety; verification of secondary voltage, seals, locking rings, etc.).
- Meter-to-RF network communication verification.
- Minor premise repairs; meter exchange; customer location validation (multi-unit); door key management; installations in small percentage of locations that are hard-to-access and that require multiple attempts to gain access to complete the installation.
- Exceptions management (when there are misalignments and inconsistencies in the work order management system and the billing and other systems-of-record regarding last read, meter location, meter identification, customer location and customer record.
- Identification of potential theft or tamper conditions.
- GPS coordinates data collection.
- Scrapping of meters; hazardous materials management.
- NOTE: Project Management Office (PMO) and "cross-dock" management (meter holding warehousing, vehicle, training and other facility space requirements) are accounted for in the evaluation but NOT included in this unit cost to install a meter

There are numerous data tracking, exchange and monitoring requirements as part of the meter field installation work. It is the responsibility of the meter field installation contractor or responsibility center to manage these information flows. Information requirements include the following:

- ID of the installer
- Date the order is completed
- Final read from the removed meter
- Read from the meter being set
- Meter number of the meter being installed
- Meter number of the meter being removed
- Follow-up flag indicating that utility should investigate situations found at a premise such as incorrect data, safety issues, premise repairs required, date/time found, utility party reported to, and others found in the field by the installer
- Comment section to include the incorrect versus correct data found
- Premise as-found and as-left condition (based on list to be provided by utility)
- Photos of each meter removed
- Global Positioning System (GPS) coordinates of each meter installed

The meter field installation work requires comprehensive set of competencies that can be effectively planned and managed. Responsibilities include the following:

- Ability to manage complex, multi-year field installation project involving millions of meters, dozens of field crews, covering a large geographic area (Total meter volume install rates could reach over 80,000 per month.)
- Turnkey project management systems and capabilities
- Domain expertise on electric meter design and installation procedures
- The ability to design and implement novel work processes that meet specific regulatory and utility requirements
- The ability to develop, operate, and maintain a high integrity and secure work order management, inventory management, and meter testing information system
- Human resource management (recruitment, training, supervision, back office support systems)
- The ability to set up and manage a call center support apparatus
- The ability to meet utility contracting and contract management requirements such as diversity and performance bonding, if required

Miscellaneous Installation Tools

- It is assumed that there will be some additional tools/applications required to enable and support the cross-dock management of AMI meters to be deployed.
- A one-time cost of $1M in the first year of deployment is assumed adequate to account for such expenses.
- During the more detailed business planning, and meter deployment planning in particular, ComEd will more formally assess and determine what tools and/or applications are required to support cross-dock operations.

E.5 AMI RF Communication System Costs (Excluding Meters)

AMI System—Implementation Support Services

ComEd has worked with a leading AMI system provider to develop estimates of the cost of deploying a RF smart metering system throughout its service territory. ComEd has also relied heavily on its Pilot Learnings to determine the overall RF system requirements in relation to implementation fees.

Table E.3 below shows estimates of ComEd's expected implementation services costs to design, plan, and implement the RF communication system. The costs differ depending on the deployment scenario. The costs shown are yearly costs for the duration of the deployment term. Furthermore, it is assumed that ComEd may be responsible for cost increases due to escalation adjustments which may be part of any vendor contract. (Values are approximate.)

Table E.3 Implementation Support Services

Implementation Support Services (per year)	5-year Deployment	10-year Deployment
Project Management	1,100,000	700,000
Network Services	2,200,000	1,750,000
Integration and Configuration Services	200,000	200,000
Training	20,000	20,000
Product Support	1,540,000	430,000

Over the five-year deployment term, and factoring in escalation, ComEd will incur costs of approximately $27 million for these implementation support services.

AMI System—Smart Metering Operating System Software

ComEd has developed cost estimates for the costs to acquire the rights of use of the RF Communication vendor's system operating software. ComEd has also developed price estimates for the on-going operations support of this system. These price estimates are unique to ComEd's specific requirements in terms of scale, capability, timing, and environments (production, test, disaster recovery, and development).

Table E.4 System Software Related Costs (Five-year deployment)

System Software Related Costs	Five-year Deployment
System Software	7,000,000
System Software Yearly Maintenance	1,200,000
Operating Agreement	~ 3,000,000 to 5,000,000 smart meters per year

E.6 IT Platform Costs

The IT platform costs (Hardware, Software, Implementation, and On-going Support) to support the full AMI deployment and business functionality have the following solution architecture components to transform related business processes and achieve optimal performance:

- Meter Data Management System (MDMS) Platform and Service Oriented Architecture (SOA) Platform
- Data Integration and Reporting Platform to support analytical needs
- Billing system/Customer Information System Platform enhancements

Business Functionality

ComEd IT plans to support AMI business case by building/enhancing the AMI pilot system environment and streamlining various business processes to enable the business benefits in various business functional areas such as:

Table E.5 Business Functionality

Functionality	In Scope	Out of Scope
Meter Deployment	• Forecast and Planning • Procurement and Receiving • Customer Calling • Meter Exchange (non AMI to AMI, AMI to AMI) • BPM Dashboard • Fixing Full-Deployment issues	• Integrating Procurement/Vendor contracts to other IT systems such as Passport • Storing of meter attributes in GIS/updating network model • Reporting CIMS WFMs/Back office work activities in the Dashboard
Billing	• Meter Reads Repository • Billing – Support Watt-Hour, Recorder, Demand billing • Potential changes to Retail Office • Ensure MDMS is the repository and CEDAR system as the billing calculator	• New Pricing Programs and functionality that was performed outside of CIMS during AMI Customer Application Program (CAP)
Web Presentment	• Web Presentment extract to a third-party web site	
Remote Connect/Disconnect	• Move-In/Move-Out, Cut-In-Cut-Out, VRU support	
Revenue Protection	• Functionality as offered in MDMS product • Advanced Analytics of the events • Additional FTEs	
Outage Management	• Confirmation of Outage Restorations (Levels 1-3)	• Levels 4-8
Meter Events	• Storing of Meter Events and provide standard reporting in the MDMS platform	• Advanced Analytics of the events
Business Readiness (Training/Performance Management, Service Introduction)	• Support as provided during the pilot for job design, training program, system transition to support team	• Detailed job design, change management on the business side
Business Intelligence (BI)/ Analytics	• Reporting through the MDMS platform	

Solution Architecture Approach

To enable the AMI functionality, ComEd IT leverages an SOA to integrate seven major IT systems, including an MDMS, multiple legacy back-office systems, customer information and billing systems, and externally hosted vendor systems, such as AMI data collection and meter deployment systems. The SOA architecture utilizes Enterprise Service Bus (ESB) and Business Process Management (BPM) product suites. Using this combination of components, ComEd IT has developed an event-driven architecture to bring about the following business benefits:

- Coordinate/synchronize the meter exchange status information across various IT systems in near real-time to provide data integrity in order to "set" the smart meter.
- Display meter status on a central dashboard to assist with AMI operational support.
- Certify meter routes as “ready to bill” by systematically ensuring communication criteria are met and supporting billing processes/functionality.
- Manage complex, long-running transactions for operational activities, such as remote connection and disconnection of customer electric service.
- Leverage Web services to provide application integration across internally and externally hosted systems.
- Provide energy usage data for AMI customers on the Web.
- Enable BI capabilities/support.

General IT Inputs and Assumptions

- AMI System environments will be available as follows: production, staging, product test, verification test, and two development environments. The production and staging environments are standalone and dedicated with the staging environment being an exact duplicate of the production environment. The other environments are implemented as multiple logical (or virtual) systems operating on multi-processor, multi-core systems
- Future hardware procurement (class/model) will provide improved hardware capability/performance at the current investment dollars level (i.e., provide increased performance for the same cost), thus allowing us to replace/upgrade/add servers to address full-growth volume and system scalability/performance needs without increasing hardware investment.
- Procurement contracts (e.g., MDMS software, storage) will be setup as a multi-year contract to align with the planned meter rollout count, thus reducing life cycle costs.
- Maintenance for some of the software license units will not be renewed once AMI steady-state is reached in 2017. These licenses are needed as a one-time need to support the AMI smart meter volume deployment during the project implementation but are not needed during steady-state.
- The pilot environments for test and development will not be replaced or scaled up for full implementation, but will be replaced as part of the hardware refresh program.
- Production and staging environments will be replaced and scaled up for full implementation.
- Server hardware is refreshed every three years per ComEd IT standards.
- Storage hardware is refreshed every four years per ComEd IT standards.
- Requirement to house/maintain 13 months of interval usage for all smart meters.

Meter Data Management System (MDMS) and Service-Oriented Architecture (SOA) Platforms

The MDMS platform provides the meter data management capabilities and support back office and external partners, vendors, and ComEd customer data needs. This system will be used to store the meter reads and serve as the meter data repository and enable meter data specific functions (e.g., versioning, VEE—Validation, Estimation, and Editing). The MDMS will act as the platform to enable various back office capabilities such as billing, web presentment, revenue protection, and business intelligence/analytics.

The SOA platform consists of ESB, Business Process Management (BPM) suite, and other middleware technologies to enable application integration between MDMS platform and ComEd back-office systems (e.g., CIMS, OMS), and external vendors/partners (e.g., AMI vendors, web presentment). IT will expand/enhance the SOA platform to address process and service integration and utilize an event-driven approach.

The above solution architecture enables back-office integration flexibility and improves reusability in addition to supporting scalability and performance while reducing business operational risk during the critical smart meter deployment phase.

The following cost categories are used to enable the MDMS and SOA platforms:

Hardware

- About $2.5M hardware investment is planned to replace/upgrade existing servers to support full-deployment. There are about 40+ servers configured in physical and virtual architecture to support software product vendor specifications and to address performance requirements.
- Production and Stage servers will be upgraded to higher class servers to support the full-deployment volume growth and functionality needs to ensure optimal system performance. These servers will be replaced on a three-year lifecycle planning program, starting from 2012.
- The existing development and test environments will not be upgraded but refreshed as part of three-year lifecycle planning program, starting from 2012.
- The hardware investment includes server procurement, installation, server configuration, clustering, integrating into IT network, and other activities that are needed to baseline the servers prior to transitioning this equipment to the IT application development team to perform software development.
- Additional investment will be made to create and support Disaster Recovery environment at an initial capital cost estimated at $850,000, starting from 2012. This environment will also follow a periodic three-year hardware refresh.
- Labor and product vendor's yearly ongoing operating and support costs are based on the hardware class/models and operating system (e.g., Windows/UNIX) and are about $13,000 to $55,000/server/year. The costs include server support, system and network administration, backups, floor space, power, air conditioning, etc.

Storage

- About 12 terabytes of storage (Tier 1) acquired for the pilot; this will continue to be utilized in the full implementation.

- Additional storage will be installed to support additional meter deployment: 14 terabytes in each of 2013, 2014, 2015, and 2016 with 13 being released in 2017 for a total of 55 terabytes of storage in the steady state.
- About $1.4M storage investment is planned to host the smart meter data to support full-deployment and steady-state needs.
- Storage needs supports the business requirement of 13 months of interval usage data.

Labor and product vendor's yearly ongoing operating and support costs at steady-state for the Tier1 fully-loaded storage platform are estimated at $38,000/TB/year. The costs include SAN support, system and network administration, backups, floor space, power, air conditioning, etc.

Software

- About $11M Software investment in MDMS, Database, and SOA/Middleware product software licenses is planned to expand/build on top of the current AMI architecture to align with the hardware class/model specifications in order to scale and support the larger volumes of transactions resulting from the data generated by the meters as they are deployed for full production These license fees are phased-in to align with the meter deployment rollout.
- Ongoing O&M software maintenance is 22%, commencing in the year after installation.

Solution Development and On-Going Application Support:

- Implementation costs during project development are based on what we learned from the pilot, fixing pilot defects, implementing full-deployment needs, support AMI requirements, performing major upgrades and data conversions to MDMS platform during the full-deployment meter time period. This is a split across multiple parties—System Integrator (System Integrator, product vendor subject matter experts), IT (Management/Project team, application support teams and project/support team contractors).
- About $36M is being estimated to execute the various business functionalities that are currently identified in the business case.
- Labor's yearly ongoing application maintenance and support cost at steady state is estimated around $4.6M.

Data Integration and Reporting Platform

The Data Integration and Reporting platform will be expanded to support data integration needs for ComEd AMI deployment to address technical requirements such as bulk data transformations, data conversions, enable reporting needs, etc. The AMI solution architecture will integrate this platform with MDMS/SOA platforms to leverage the appropriate toolsets for various data extraction, transformation, and reporting needs.

Hardware and Software:

- Additional data integration and reporting hardware is estimated at $500,000 in 2012.
- Ongoing hardware operations are at $55,000 per year.
- Additional software licenses are estimated at $1,000,000.
- Ongoing software maintenance and operations is estimated at 20% or $200,000 per year.

Solution Development and On-Going Application Support:

- Implementation costs during project development are based on what we learned from the pilot, fixing pilot defects, implementing full-deployment needs, and support the new AMI business requirements. This is a split across multiple parties – System Integrator (System Integrator, product vendor SMEs), IT (Management/Project team, application support teams and project/support team contractors).
- Costs are included in the MDMS/SOA platform as these tools are needed by the application development team to address business functionality needs.

Billing System - Customer Information System (CIMS) Platform

The Customer Information and Management Systems (CIMS) platform houses ComEd customer data and supports the various Customer Operations functions such as customer care, billing, service orders, and several back office functions. This platform will be enhanced to support both the volume of meter exchanges occurring during smart meter deployment and the increased volume due to all the activities associated with deployment forecasting and planning. In addition, the system will also be enhanced to improve integration between MDMS and CIMS/CEDAR for billing purposes, to enhance the remote service switch process, and to improve information availability for customer care support.

The following cost categories are used to enable the Billing/Customer Information System platform:

Hardware and Software:

- Additional mainframe capacity is needed to support full-deployment meter exchange volume for the CIMS system needs. This is estimated at $500,000 in 2012.
- Ongoing operations are estimated at $200,000.

Solution Development and On-Going Application Support:

- Implementation costs are driven by the effort needed to expand the architecture for full volume deployment. This effort includes optimization of infrastructure and design based on pilot learnings, as well as the enhancement of functionality to best support business processes. This is a split across multiple parties—System Integrator (System Integrator, product vendor subject matter experts), IT (Management/Project team, application support teams and project/support team contractors).
- About $6.5M is being estimated to execute the various business functionalities that are currently identified in the business case.
- Labor’s yearly ongoing application maintenance and support costs at steady state are estimated around $500,000.

E.7 Project Management Office and AMI Operations

Project Management Office

- The Project Management Office (PMO) functions will be performed during the project planning and implementation stages (including during AMI deployment).
- Hold responsibility for Scope, Schedule, Budget, and Quality of Smart Meter deployment plan.
- Drive the installation schedule with internal ComEd business lines and external stakeholders.
- Provide Meter Inventory Management.

- Make project level decisions, develop project plans, estimate work, and schedule tasks.
- Provide budget reporting, schedule progress reporting and performance indicators.
- If required, manage contracts for vendors including but limited to meter deployment and field installation tool.
- Hold responsibility for developing and managing project plans and SLA's.
- Collaborate with vendors, consultants, and others to achieve pilot results to meet defined business needs. Provide technical and administrative guidance to project staff as needed to carry out project work plan actions.
- Monitor changes in technology and maintain a current awareness of industry trends and long term technology plans.
- Lead cross-functional teams or projects to achieve milestones and objectives. Assists with planning, directing and reviewing the day-to-day work of other team members and will occasionally present topical matters to senior leadership.

General AMI Operations Assumptions

Customer Operations' organizational structure and responsibilities remains the same. For example:

- Revenue Management still issues the cut-out orders.
- F&MS is still executing the meter investigations after the deployment of a geographic area.
- Communication Department will develop and manage the overall communications plans for the Smart Meter customers. Business/Customer Experience Department will be responsible for the execution of the plan.
- IT will be staffed appropriately to support the transfer of data from the head-end, MDM, CEDAR, to CIMS for billing, remote connect/disconnect and other requirements.
- F&MS or a contractor is responsible for physical installations of meters. They are responsible for all deployment activities around installing the meter: personnel, automated outbound calls, installation letters, door knocks, door cards, appointments, repairs, call backs, etc.
- F&MS or another entity is responsible for testing the meter when received from the vendor. This includes customer complaints and possible testing of the old meter.
- IT enhancements will be implemented during the deployment period so AMI Operations staff reductions can occur to reach steady state FTE numbers.
- Smart Meter Operations will perform three core functions that will scale and peak during the deployment and drop in post deployment—MDMS Operations, Smart Meter Field Operations, and Smart Meter Business/Customer Experience.

MDMS Operations

- Ensure accurate and timely Smart Meter Readings are acquired for customer billings on a monthly basis and to maximize performance of System Billing.
- Manage field/service order completion process for the meter exchange to ensure the meter sets down properly in CIMS.
- Work closely with IT to analyze and generate reports on meter IT network issues and verifying that all systems are updated and in sync.
- Work closely with IT to minimize exceptions during the exchange (WFM, DNAC, etc.) and billing.

- Report and monitor Smart Meter reading and billing on a daily basis.
- Generate field orders for Smart Meter Field Operations to investigate.
- Prioritize field orders for Smart Meter Field Operations to investigate based on consecutive estimate or size of customer.

Smart Meter Field Operations

- Generate and prioritize field orders for F&MS to execute to resolve billing and remote disconnect/connect issues.
- Provide technical leadership (hardware, software, communication paths) in meeting the technology needs of the Smart Meter network including network analysis and proposed solutions.
- Manage the meter status, events, and flags in the smart meter headend operating system.
- Manage and evaluate field options for billing issues generated by MDMS Operations.
- Manage connect/disconnect exception process and exceptions.
- Determine when other technologies are required when meter(s) is not communicating to the network.
- Management of SLA with F&MS for post-deployment activities of a geographic office.

Customer Experience

- Accountable for the Smart Meter customer experience including Call Center incoming call oversight, returned calls of escalate customer contacts, escalated complaints and claims.
- Accountable to implement process changes to enhance the customer experience around the meter exchange. Communication Department will drive the communication strategy.
- Responsible for web page (i.e., map of deployment plan) and social media outlets – deployment and post-deployment.
- Accountable to monitor the feedback around the meter exchange process and recommend changes when required.
- Promote business opportunities in support of various ComEd groups to leverage the Smart Meter investment in data and systems available for their business purposes to enable them to increase productivity and customer satisfaction, reduce cost, and generate revenue.
- Assist in developing and implementing communication and change management plans for ComEd.
- Responsible for the implementation of internal ComEd training.

E.8 Other Cost Inputs and Assumptions (to Achieve Estimated Benefits)

Cross-Dock Management – Tools and Applications

- The cross-dock operations are assumed to be staffed by internal Supply personnel for the duration of the meter installations.
- Three cross-dock operations are assumed to be in operations simultaneously
- To account for anticipated additional costs to manage cross-dock operations during the deployment period, the evaluation has included a one-time cost of $1M in the first year of AMI meter deployment for testing equipment and any other tools / applications that are deemed necessary.

Revenue Protection – UFE

- To achieve the estimated UFE benefit, there will be incremental costs (relative to current operations) due directly to a tool/application and analysts.
- A one-time $1M software and implementation cost is estimated for a theft/tampering application. An on-going annual cost of $200,000 in annual support fees and maintenance is also estimated.
- An additional two theft (field) investigators are expected to be required at an estimated total annual cost of $400,000.
- An additional three Revenue Protection analysts are expected to be required at an estimated total annual cost of $525,000.

Revenue Management – Bad Debt

- Per current ComEd business rules, remote-disconnects will not be performed for non-pay on medical stays (life support certifications) nor during winter moratorium.
- An additional two FTE in the Revenue Management area are estimated to be required to achieve the benefits associated with an increased number of disconnect due to non-payment.

Other Customer Benefits

- There will be a web page for customers to monitor, view, and reduce their usage. This assumes approximately $600,000 annual licensing and support costs, and that the web page will be accessible to the customers through ComEd.com.
- ComEd Corporate Communications will develop and Implement a Customer Communication and Education strategy campaign. This will be implemented during meter deployment under both the five-year and ten-year deployment scenarios. The funding for this will be $50M to be distributed evenly throughout the deployment period ($5M/year for the 10 year deployment scenario and $10M/year for the five-year scenario).

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Appendix F: Detailed Benefit Descriptions

F.1 Revenue Protection—Reduction in Unaccounted for Energy (UFE)

Business Owner and Organization / Department

Revenue Protection

Background and Description of Benefit

Revenue Protection is responsible for managing two main benefit categories: 1) Consumption on Inactive Meters (CIM) and 2) UFE. The first benefit is associated with metered electricity that is socialized over all ComEd customers due to no customer on record. The second benefit relates to unmetered electricity usage due to a variety of causes, predominantly theft of service that is socialized over all ComEd customers.

Revenue Protection is responsible for reducing the occurrence of theft, tamper, inactive accounts, and other meter activities and customer behaviors that result in provision of energy services without payment.

RP04 is concerned with a portion of this loss, namely the theft of energy through tampering with the meter or bypass of the meter, and energy loss due to stuck and slow meters (i.e., meters that need to be replaced and are well outside of tolerances), "closed loops"89, meter constant errors, and improper account set ups.[90] The table below shows the GWhrs and value of this loss (2010 baseline values).

	2010 baseline – GWh / yr	50% reduction (GWh / yr)	Value (@ rate = full bundled service, ~ 12.05 cents, 2010 rates) $1000s
Residential	793.0	396.5	47,771.0
Commercial	99.6	49.8	4,726.0
Total	892.6	446.3	52,497.0

ComEd plans on using the smart meter's event detection capability (e.g., tamper flag) to reduce the amount of energy loss due to these circumstances. The event detection capability is estimated to impact 50% of the unaccounted for energy.

ComEd will need to thoroughly understand and field-validate all current AMI tamper flags. It is possible that certain flags may need to be adjusted once field validations take place and the linkage to the flags is better understood. It will also be necessary to have a reliable data mining and reporting tool to allow Revenue Protection to determine where to focus its back office efforts and field investigations. The tool would also lend itself to identifying possible theft of service where current tamper flags would not generate a notification.

Impact / Handling of Benefit - Impact on Revenue Requirements

This is a benefit that flows directly to all ComEd customers through lower energy charges. The assumption is that each UFE event will result in the situation being corrected and the customer causing this event to cease theft of electricity and that meter equipment is maintained to measure usage properly. Unlike CIM customers, It is not as likely to bill theft customers for electricity going forward, whereas much of this type of customer base does not remain on service for any extended amount of time. To the extent ComEd can field and stop theft of service on a timely basis, all of ComEd's customers will pay less in Purchased Energy Adjustment (PEA) costs due to the

[89] Closed loops refer to circumstances where load is being served without a meter set. This might occur, for example at a construction site

[90] Improper account set up may occur when the meter identification, premise identification and customer identification have not been properly linked. Load is being served until the situation is remedied.

reduction in the UFE occurrences and the associated consumption.

Customer savings are reflected in the change in revenue requirements (as a component of total revenue requirements). **Revenue Requirements** will decrease**.**

Functional Requirements to Achieve Benefit

Smart meters are deployed that detect a variety of meter events, store these events, and deliver this information back to ComEd's computer systems on a daily basis.

Reliable data mining and reporting tools from ComEd systems and other back-end processes that allow Revenue Protection to determine where to focus its back office and field investigations.

The smart meter solution needs to utilize meters that have meter event detection, storage and delivery capabilities; a head end system that delivers this information to the meter data management system; and a reporting system that Revenue Protection utilizes to identify and prioritize meter events. The tool/system will lend itself to identifying possible theft of service where current tamper flags will not generate a notification. (see incremental cost to achieve section)

Business Process Changes to Achieve Benefit

In addition to the functional and system requirements, the revenue protection processes for tamper/theft will be modified to address the new source of events reported on by the smart meter system. Also, the newly created AMI Operations department will have a role in the monitoring of the meter event information from meter to MDMS to ensure its reliable acquisition and delivery to Revenue Protection for investigation.

Benefit: Metrics and Key Assumptions

This benefit calculation is dependent on the following metrics and key assumptions:

- ComEd has determined the total Gigawatt-hrs/yr associated with UFE.
- It has assigned 50% to circumstances that will be diagnosable and detectable with assistance through the AMI automation. This UFE has been decomposed into residential and commercial.
- ComEd's costs to supply this consumed but unmetered, unbilled and unpaid energy use by the cost causer
- It is not assumed that the 50% diagnosable UFE will result in a contact from a customer to establish service at ComEd. It is possible that 20-50% of the 50% diagnosed UFE could lead to a billable customer, however no data exists to further refine this estimate. For the base case the assumption is that 20% of the energy is billable (i.e., delivery service is included on 20% of diagnosed UFE energy).
- Growth in the system. It is assumed that ComEd's costs to supply this unbilled and unpaid energy use will grow as the system grows (under the "as is" scenario).
- The benefit is also dependent on the rate of escalation in distribution system costs and energy costs. At the present time ComEd is modeling this as zero percent change.
- The benefit is dependent on phase in assumptions (i.e., the rate of phase in of the AMI network). If, for example, 10% of the core deployment is completed, then it is assumed that 10% of the unbilled can be avoided. This phasing also allows for the phasing in of the new ComEd work practices associated with the new business rules.

Benefit Realization Schedule

The benefit realization schedule would match the deployment of smart meters.

Incremental Costs to Achieve Benefit

The smart meter will need a meter data management/analytical reporting system to identify and prioritize meter events. The tool/system will lend itself to identifying possible theft of service where current tamper flags will not generate a notification. Cost of tool – $1,000 K one time cost (software and implementation), $200K annual support fees.

Additional analyst support of 3 FTEs will be necessary to manage and monitor the data mining/analytics/reporting tool that will be utilized. Estimated cost = $525K annually.

Additional 2 management theft/field investigators will be necessary to assist with the field force investigations - $400.

There may be incremental costs to Field Operations associated with achieving this benefit. Expected volumes of tamper flags will increase significantly compared to current state, whereas current state allows for little to no tamper detection. The expected tamper flag increase will result in necessary field validations, which will require timely field visits in order to rectify tamper situations in an expeditious manner. Timely field validations are imperative to reduce UFE losses.

Refer to Field & Meter Services "To-Be" work plan to see the number of orders estimated to field investigate the UFE events.

Benefit Calculation

The annual UFE is based on a 2009 loss analysis prepared by Finance and Engineering. The non technical line loss UFE is estimated at .91% of annual zonal load. This total annual UFE in kWhs is further reduced by 50%, whereas we do not believe that every theft situation will be flagged or identifiable and hence fielded in a timely fashion to stop the usage. The energy cost is estimated to be reduced to the above mentioned 50% as a reduced pass through cost to customers. It is not anticipated that the full 50% distribution costs will be tied to a new billable customer, but that 20-50% of the 50% theft estimate could lead to a billable customer. For the base case the assumption is that 20% of the energy is billable (i.e., delivery service is included on 20% of diagnosed UFE energy.)

Benefit Realization Schedule: Benefit would be realized as the AMI system is deployed.

Growth: This benefit would grow as the system grows.

Escalation: This benefit would increase with the rate of escalation in the value of energy..

Pilot Findings / Results to Support Estimated Benefit

Minimal UFE pilot results exist to date. ~2,800 remote disconnects led to ~600 meters/customers that did not connect. 145 tamper flags resulted on these 600 meters. Only 22 flags have been field validated, resulting in 7 confirmed tamper situations.

Supporting Data

Table 1: Estimated UFE Savings

Delivery - Distribution	$	15,940,811
Delivery - Transmission	$	2,894,510
Other Revenue	$	2,166,005
Delivery Subtotal	**$**	**21,001,326**
Energy	**$**	**31,495,435**
Total	**$**	**52,496,761**

F.2 Revenue Protection—Reduction of Consumption on Inactive Meters (CIM)

Business Owner and Organization / Department
Revenue Protection
Background and Description of Benefit
Revenue Protection is responsible for managing two main benefit categories: 1) Consumption on Inactive Meters (CIM) and 2) Unaccounted For Energy (UFE). The first benefit is associated with metered electricity that is socialized over all ComEd customers when there is no customer on record to bill for the electricity consumed. The second benefit relates to unmetered electricity usage due to a variety of causes, predominantly theft of service, that is socialized over all ComEd customers. RP03 is concerned with the first benefit category (i.e., CIM). ComEd plans on using AMI's automation of the disconnect/reconnect switch capability to significantly reduce the amount of CIM occurring on the system. As part of deployment, CIM locations will have smart meters installed with the switches disconnected soon after the installations are completed. Customers wanting service will be required to contact ComEd and establish a premise and customer identification to the metered location. CIM results when the ComEd customer of record finals his/her account and there is no immediate successor customer that contacts ComEd to place the account in his/her name. ComEd's current practice is to leave the power on and whatever electricity is consumed at the premise continues until either a new customer establishes an account or a field order is generated to manually disconnect power when the accumulated usage exceeds a minimum amount. ComEd tracks the total energy consumption on CIM by way of the regular monthly meter reading. ComEd retains the monthly usage information even though a bill is not generated. In 2010 there was an monthly average of 139,861 inactive accounts. The number of CIM accounts fluctuates month-by-month. Revenue Protection's current practice is to monitor inactive accounts that exceed a threshold of 1,000 kWhrs of consumption and prioritize the field disconnection of power at these locations. For 2011, the plan is to issue field disconnection orders for approximately 49,000 locations. Overall, the CIM accounts are responsible for using 516 Gigawatt-hrs (GWhrs) of energy per year (based on 2009 and 2010 averages). The benefit assumes that when customers final their account, a computer generated order will disconnect the power on the customers' move out day. Furthermore, because the automated switch is limited to single phase meters with a rating equal to or under 200 amps, the benefit does not apply to all CIM meter locations. Specifically, ComEd reduces the CIM volume by the approximate number of transformer- rated and/or three-phase meters, which are not equipped with the automated switch. This results in a residual amount of energy that can be targeted for reduction through deployment of smart meters with the disconnect ability. • Approximately 3.1% of all of ComEd's meters are transformer rated. It is assumed that this percentage applies to CIM accounts as well. Approximately 5% of the total energy is identified with these transformer rated CIM accounts. • This leaves a "target" balance of CIM-related energy at 490.0 Gigawatt-hrs of energy / year (516 less 26 yielding 490). - 55 GWhr / year is assumed commercial premise related - 435 GWhr / year is assumed residential premise related ComEd assumes that it can reduce the target balance of CIM by 90%. It is consistent with ComEd's use of the disconnect switch as part of the pilot. This represents the degree of reliability of the end-to-end business processes necessary to reliably use the switch. This is conservatively lower than the expected switch failure rate (approximately 3%) to account for business process changes, exceptions and other issues. Finally it is assumed that approximately 100% of the CIM premises disconnected with automation will revert to a paying customer. Once disconnected, these customers will be motivated to properly establish service by contacting ComEd and providing necessary information for the account to be established.

Impact / Handling of Benefit - Impact on Revenue Requirements
This benefit is a pass thru benefit to the end customer. At an aggregate level, Revenue Requirements will decrease by the estimated reduction of CIM charges. As a result, customers will ultimately pay less due to this reduction in CIM which is currently "socialized" and recovered from all ComEd customers through the UFE Rider.
Functional Requirements to Achieve Benefit
There are four main functional requirements in order to fully realize the calculated benefit: 1. At the time of installation, the switch is opened to disconnect power soon after the installation is completed 2. The switch is automatically opened to disconnect power when customers' final their accounts 3. The switch is automatically closed to connect power when new customers establish their accounts 4. Select ComEd personnel have the ability to remotely disconnect/reconnect power on a meter-by-meter basis as a backup capability Existing processes will need to be redesigned with supporting change management and training of affected work groups such as the Call Center, Billing, Field & Meter Services along with Revenue Protection.
Business Process Changes to Achieve Benefit
ComEd will have to "provision" the AMI remote disconnect and reconnect capability (which is governed through the AMI "head end" control system) to customer care, F&MS or other responsible parties who will perform the disconnection and reconnection actions. Some form of batch process can be established within the AMI system to automate this process, but presumably there will have to be verification steps involved in ensuring the correct customer and meter identifications are loaded into this batch process.
Benefit: Metrics and Key Assumptions
This benefit calculation is dependent on the following metrics and key assumptions: • ComEd has determined the total Gigawatt-hrs/yr associated with CIM. It has decomposed this into residential and commercial (subject to use of the switch) and a residual that is outside the scope of the benefit (transformer-rated and three phase meters). Furthermore, through pilot learnings, ComEd is assuming that the inactive kWh benefit "hit" rate is 90% (including failed remote disconnects). • ComEd's costs to supply this consumed but unbilled and unpaid revenue. • Growth in the system. It is assumed that ComEd's costs to supply this unbilled and unpaid revenue will grow as the system grows (under the "as is" scenario). • The benefit is also dependent on the rate of escalation in distribution system costs and energy costs. • The assumption that virtually 100% of customers impacted elect to contact ComEd and properly establish service. • The benefit is dependent on phase in assumptions (i.e., the rate of phase in of the AMI network). If, for example, 10% of the core deployment is completed, then it is assumed that 10% of the unbilled can be avoided. This phasing also allows for the phasing in of the new ComEd work practices associated with the new business rules. • Under the "As Is" scenario [no automation], and with Revenue Protection working ~ 49,000 accounts on an annual basis, ComEd will <u>*continue*</u> to experience the CIM-related loss 516 GWh /year. This loss is a form of cost experienced by all of ComEd's paying customers through the Purchased Electricity Adjustment (PEA).. • With automation, it is assumed that virtually all of the CIM accounts will be disconnected which are provisioned with the automated disconnect switch, and therefore the CIM will be eliminated. • It is assumed that ~ 100% of the successful remotely disconnected CIM premises will contact ComEd to establish service. This consumption moves to metered revenue. • It is assumed that ComEd working capital requirements will not be significantly impacted and are ignored for purposes here.

Impact on Electricity Delivery Reliability

Reliability improves when ComEd improves the “resolution” of its service base: meter identification, premise identification, customer identification. With the opportunity afforded through automation, and the new business processes and rules around use of the automated switch, ComEd aims to improve its resolution in this important area of the ComEd business. Assuming the historical levels of CIM-related accounts, and churn within these accounts, there are hundreds of thousands of ComEd system customers for whom ComEd is unable to provide the best possible service due to this lack of resolution.

Benefit Realization Schedule

The benefit realization schedule would match the deployment of smart meters.

Incremental Costs to Achieve Benefit

It is assumed that there is no change in Revenue Protection resources or costs to achieve this benefit. Rather, automation permits new business rules to be established that allow Revenue Protection to meet is organizational goals more effectively. Today, due to staffing limitations, it is not possible or practical to disconnect all CIM-related premises / customers.

The Field & Meter Services scorecard will capture the favorable impact on the volume of CIM orders that will need to be field completed by Energy Technicians.

Benefit Calculation

Refer to inputs and assumptions listed above that drive the calculation of the final annual savings as shown below.

Benefit Realization Schedule: Benefits will be realized as the AMI system is deployed.

Growth: This benefit would grow as the system grows.

Escalation: This benefit would increase with the rate of escalation in the value of energy. At present, ComEd assumes zero percent change in energy costs.

Pilot Findings / Results to Support Estimated Benefit

The Pilot helped ComEd determine the practical changes necessary to achieve an automated disconnect capability.

Secondly the pilot helped determine the reliability of the switch’s operation and the percentage of customers (at least 76%) falling into the CIM area that immediately contacted ComEd to establish service.

Supporting Data

Table 1: Estimated Consumption on Inactive Reduction

Delivery - Distribution	$	15,750,904
Delivery - Transmission	$	2,860,027
Other Revenue	$	2,140,201
Delivery Subtotal	**$**	**20,751,132**
Energy	**$**	**31,120,222**
Total	**$**	**51,871,354**

F.3 Revenue Protection—Improved Meter Accuracy (No Quantified Benefit)

Business Owner and Organization / Department
Field Meter Services (F&MS) is responsible for meter testing and ensuring meters meet strict ICC and ComEd tolerances. Revenue Protection is responsible for determining the economic value of any over/under metering inaccuracies based on the test data provided by F&MS.
Background and Description of Benefit
The smart meter is a more accurate measurement device. Since all of ComEd's existing meters will be replaced with a smart meter, the aggregate level of accuracy will improve. Electro-mechanical (EM) meters, while verified to be within the strict tolerances established by the ICC, tend to run slightly slower with age. Hence the accuracy bias is to increase the measured number of kWhrs (consumption) once the smart meter is installed (i.e., shifts unmetered kWhrs from line loss to the cost causer).
Impact / Handling of Benefit - Impact on Revenue Requirements
From a rate payer business case perspective, the project team concluded that there is no net benefit to the customer given the random nature of the meter inaccuracy. There will be "winners" and "losers" as the unmetered usage becomes metered. **No Net Impact to Revenue Requirements**. More accurate meters do not impact Revenue Requirements. Customers use the same amount of electricity, so the total kWh used by customers does not change (before and after AMI). Rather, there are kWh that are not metered that are reflected in Unaccounted for Energy (UFE). The energy component of the customer's bill includes an allocation for UFE, but this is a pass thru. Therefore, if UFE decreases, this allocation component also decreases. **No net impact to customer pass-thru benefits.** A more accurate meter will allocate customer costs from the UFE-related cost allocation (part of the customer energy bill) to metered revenue (which includes the pass thru energy component), but the net impact to the customers in aggregate is zero. Fairness improves to a degree because the meter inaccuracy is not identical for each meter resulting in some customers being over-allocated the socialized pass thru cost and some customers being under-allocated the socialized pass thru cost. While delivery services revenue may marginally increase with the increased kWh metered and billed the delivery services charge, the argument is that with frequent rate cases the cents/kWh will be constantly adjusted to reflect the new metered usage.
Functional Requirements to Achieve Benefit
The smart meter is factory calibrated and tested. It is also sample tested by the utility as part of the meter acceptance process before delivery to the field for installation. No on-going field or shop calibration is needed.

F.4 Revenue Management—Reduction in Net Bad Debt Expense

Business Owner and Organization / Department
Revenue Management
Background and Description of Benefit
When customers are unable or refuse to honor their billing commitments, ComEd must eventually recognize this unpaid usage as a bad debt and it is charged-off. This cost is "socialized" across all of ComEd's paying customers. With the AMI-enabled disconnect switch, ComEd's Revenue Management business area will be able to adopt new business rules that will better ensure that potentially underperforming customer accounts are managed in a way that reduces the size of the uncollectable charge-off and ultimately the bad debt expense. ComEd classifies the uncollectable customers into three groups: • **Bankruptcy charge-offs –** Amount of pre-petition accounts/debt that is written-off upon notice of customer bankruptcy • **Non-Pay Cut-off charge-offs –** Amount of accounts/debt that is written-off after a cut for non-payment occurs and there is no resulting payment for service restoration. • **Voluntary Final charge-offs –** Amount of accounts/debt that is written-off after the prior customer finals their account on their own or another applicant requests service at that premise and the prior customer does not pay their final bill. Key Consideration: The benefit captured and estimated here pertains to the reduction in bad debt. This particular benefit is not associated with the avoidance of the field trip to manually disconnect these customers. The avoided field trip benefit is accounted for under the Field & Meter Services (F&MS) functional area. With the disconnect automation functionality under AMI ("To-Be"), ComEd will be able to remotely disconnect customers after the customer bill reaches a certain dollar and time-based threshold, rather than needing to disseminate the work through field crews for manual disconnect. The time threshold is estimated to be three months of unpaid bills, while the dollar threshold will be set uniquely for residential and commercial customer classes. Under the current business practice ("As-Is"), while there is a dollar and time threshold to determine which customers are eligible for disconnects, the volume of eligible customers exceeds ComEd's back office and field work capacity and therefore not all eligible customers are disconnect further increasing bad debt. With AMI automation and specifically the remote disconnect functionality, new business rules and thresholds can be established, and not constrained by back office and field work capacity. Not all of ComEd's meters will have this disconnect capability. This capability is limited to single phase meters with a rating under 200 amps. This is estimated as 95% of ComEd's meters.
Impact / Handling of Benefit - Impact on Revenue Requirements
This benefit is a pass thru benefit to the end customer. At an aggregate level, Revenue Requirements will decrease by the estimated net reduction of bad debt expense. As a result, customers will ultimately pay less due to this reduction in bad debt expense which is currently "socialized" and recovered from all ComEd customers through the Unaccounted for Energy (UFE) Rider.
Functional Requirements to Achieve Benefit
Enablement of the remote disconnect/reconnect switch. Also, new business rules for cut off thresholds (time and dollar outstanding based).
Business Process Changes to Achieve Benefit
ComEd will have to "provision" the remote disconnect and reconnect capability (which is governed through the AMI "head end" control system) to CIMS, customer care, F&MS, or other responsible parties who will perform the disconnection action. Some form of batch process can be established within the AMI system to automate this process, but presumably there will have to be verification steps involved in ensuring the correct customer and meter identifications are loaded into this batch process. Also some delinquent customers (e.g., 3 phase meters)

will not be provisioned with the automated switch capability, and these will have to be addressed through traditional means.

Benefit: Metrics and Key Assumptions

This benefit calculation is dependent on the following metrics and key assumptions:

- The number of accounts that create bad debt. This is a composite of three account types: bankruptcy, non-pay cuts, and voluntary finals. These are further expressed in terms of customer type: residential and small commercial.
- For each bad debt account type, there is an average account value that ComEd experiences today.
- The number of customers eligible for disconnection may not change in the "To-Be" scenario relative to the "As-Is". However, the amount of charge-offs and bad debt expense will decrease as customers will not be able to build up large balances to the degree they can today, and will also be more likely to pay for reconnection in the new environment.
- With AMI (the "to be" scenario), a new business rule is established for each account type (thresholds of time and dollars).
- The difference (today's experience and the "to be" scenario) is further adjusted to reflect that the automated switch capability is not available on 100% of the meters. In the case of small commercial a factor of 82% is used.
- A total of ~ 205,000 accounts will be subject to disconnect using the new proposed thresholds (versus around 120,000 today).
- The benefit is dependent on benefit realization schedule assumptions (i.e., the rate of deploying / implementing the AMI network). If, for example, 10% of the core deployment is completed, than it is assumed that 10% of the uncollectibles can be avoided. This phasing also allows for the deployment of the new ComEd work practices associated with the new business rules.
- The benefit is also dependent on growth. The level of work Revenue Management must process is assumed to increase under the "As Is" scenario. In other words, as the system grows, the level of bankruptcy and other activities here scale.
- The benefit is also ostensibly dependent on the rate of escalation in distribution system costs and energy costs (i.e., the amount subject to the bad debt categorization).
- Currently, accounts enter established collection paths via a combination of the risk segment assigned to the account based on past payment behavior w/ ComEd and an associated past due dollar threshold. This process helps ensure that ComEd is not needlessly disconnecting service to customers who may have forgotten to pay one bill and rather concentrate on those accounts that truly require service suspension. For the purposes of deriving the benefits of AMI w/ remote disconnect capabilities, this concept of maintaining a certain past due dollar threshold before proceeding w/ a disconnection was retained. Depending on risk segment, residential accounts enter collection paths at past due dollar levels from $100 to $300 and small commercial accounts enter collection paths at past due dollar levels from $200 to $500. Given average monthly bills of $86 and $373 for residential and small commercial accounts respectively, Revenue Management estimates that the number of months worth of usage on the meter at the time of disconnection ("multiplier") would be 3.0 and 2.5 times the monthly average bill for residential and small commercial accounts respectively (includes 1 month of current usage in addition to the past due amount because ComEd bills after usage has been incurred).
- Despite the ability to disconnect remotely at anytime and for any past due amount, charge-offs will continue to occur. However, due the ability to disconnect much earlier, the dollar exposure of the charged-off accounts will be much less. The differential between what ComEd currently experiences for charge-offs and what the exposure is on the meter in an AMI scenario represents the potential benefit to ComEd. This benefit number is tempered by the expected "hit rate" or ability to remote disconnect an account. The hit rate for residential accounts is estimated to be 95% based on the I-88 corridor pilot and 82% of small commercial accounts based on the current mix of non-transformer rated small commercial meters across the system currently.

- It should be noted that the analysis concentrated on a reduction in charge-offs due to how quickly accounts would be cut, rather than the ability to disconnect more accounts because the Accounts Receivable Reserve already adjusts for a certain number/amount of accounts that will not pay whether they are disconnected or not.
- While it is possible that an increase in service suspension activity would increase bad debt expense in the short term, our bad debt reserve should be structured in a way that prevents that. Therefore, we do not believe it is necessary to account for a bad debt spike in the AMI implementation assumptions. Our bad debt reserve would certainly decline as AMI is implemented as there would be fewer conditions under which we would need to carry debt that ages beyond a few months.

Benefit Realization Schedule

The benefit realization schedule would match the deployment of smart meters.

Incremental Costs to Achieve Benefit

Our estimations are that two additional employees will be needed in Revenue Management to handle the following responsibilities:

- Increase in effort to address inquiries and questions due to elevated cut activity.
- Review elevated prospective cut information on a daily basis to ensure the decision to suspend service is appropriate and timed effectively (i.e., governmental, Life Support, or other unique accounts such as hospitals, schools, day-care facilities).

These costs would amount to increased salaries of $140,000 with associated pension and benefits of P& of $117,320 bringing the total additive cost to $257,320.

Benefit Calculation

The analysis is based on a 2010 activity levels. “As Is” and “To Be” thresholds are used to drive the reduction in bad debt computation. In 2010, ComEd performed disconnects on 124,597 customers, with a total of $63.1M in total bad debt expense.

Applying new business logic (disconnect switch is used to disconnect sooner in cycle) will result in an estimated 205,000 disconnections, and a new net bad debt expense level of $32.6 million, or a reduction of $30.5M (48.4% reduction in bad debt expense).

The analysis and calculation performed to yield this estimated benefit was a two-step process:

- Calculating the % reduction in net charge-off’s as a percentage of the 2010 charge-off volumes
- Applying the % net charge-off reduction against the total bad debt expense for 2010, to yield the net bad debt expense reduction ($).

The analysis includes assumptions about the number of customers who elect to contact ComEd, pay their bill, and re-establish service. The analysis also includes correction factors for the percentage of customers who will be provisioned with a disconnect switch capable meter. Revenue Management will continue to work accounts manually if the meter is not automated with the switch. These manual disconnects are factored into the overall benefit yield.

Benefit Realization Schedule: Benefits will be realized as the AMI system is deployed.

Growth: This benefit would grow as the system grows.

Escalation: This benefit would increase with the rate of escalation in the value of the distribution and energy charges not collected.

Pilot Findings / Results to Support Estimated Benefit

The Pilot helped ComEd determine the practical changes necessary to achieve an automated disconnect capability and also demonstrated that the remote disconnection switch is functional and can work in move in/move out situations.

Supporting Data (below)

Table 1 – 2010 Charge Off Activity (using current business processes)

# of Disconnect Orders View	2010 Net Charge-offs - estimated allocation					As-Is (20 yr steady-state)
Segmentation	$		#		Avg $	# of disconnections
Additional Lift from Disconnect Switch for Existing Charged-off Accounts Due to Ability to "Cut" at a Lower Threshold						
Disconnections						
Residential/SCI	$ 27,757,894	89.2%	37,267	94.4%	$ 745	107,500
SCI/LCI	$ 3,361,903	10.8%	2,216	5.6%	$ 1,517	12,500
Total	**$ 31,119,797**	**100.0%**	**39,483**	**100.0%**	**$ 788**	**120,000**
Bankruptcy						
Residential/SCI	$ 6,743,827	81.3%	8,661	96.2%	$ 779	0
SCI/LCI	$ 1,555,570	18.7%	343	3.8%	$ 4,535	0
Total	**$ 8,299,398**	**100.0%**	**9,004**	**100.0%**	**$ 922**	**0**
Finals						
Residential/SCI	$ 15,752,100	82.5%	71,603	94.1%	$ 220	0
SCI/LCI	$ 3,344,372	17.5%	4,507	5.9%	$ 742	0
Total	**$ 19,096,472**	**100.0%**	**76,110**	**100.0%**	**$ 251**	**0**
Totals						
Residential/SCI	**$ 50,253,821**	**85.9%**	**117,531**			
SCI/LCI	**$ 8,261,845**	**14.1%**	**7,066**			
Total	**$ 58,515,667**	**100.0%**	**124,597**			

Table 2 – The “To Be” scenario (application of proposed new business rules with more aggressive thresholds, yielding 205,000 total disconnects).

Orders View	To-Be (20 yr steady-state)									
Segmentation	Remotely Cut	Manually Cut	Total	Estimated Average Balance	Cut Value	Estimated Cut-In % (Based on $)	Estimated Grosse Charge Offs w/ Switch	Net to Gross Percentage	Estimated Net Charge-off	Benefit from Reduced Net Charge-offs
Additional Lift from Disconnect Switch for Existing Charged-off Accounts Due to Ability to "Cut" at a Lower Threshold										
Disconnections										
Residential/SCI	103,740	5,460	**109,200**	$ 258	$ 30,783,126	66%	$ 10,466,263	79%	$ 8,274,843	$ 19,483,051
SCI/LCI	8,856	1,944	**10,800**	$ 933	$ 11,214,712	79%	$ 2,355,090		$ 1,861,982	$ 1,499,920
Total	**112,596**	**7,404**	**120,000**		**$ 41,997,838**		**$ 12,821,352**		$ 10,136,825	**$ 20,982,972**
Bankruptcy										
Residential/SCI	8,228	433	**8,661**	$ 258	$ 2,456,147	0%	$ 2,456,147		$ 1,941,880	$ 4,801,947
SCI/LCI	281	62	**343**	$ 933	$ 542,508	0%	$ 542,508		$ 428,918	$ 1,126,653
Total	**8,509**	**495**	**9,004**		**$ 2,998,655**		**$ 2,998,655**		$ 2,370,798	**$ 5,928,600**
Finals										
Residential/SCI	68,023	3,580	**71,603**	$ 258	$ 18,305,625	0%	$ 18,305,625		$ 14,472,805	$ 1,279,295
SCI/LCI	3,696	811	**4,507**	$ 933	$ 4,051,287	0%	$ 4,051,287		$ 3,203,031	$ 141,341
Total	**71,719**	**4,391**	**76110**		**$ 22,356,912**		**$ 22,356,912**		$ 17,675,835	**$ 1,420,637**
Totals										
Residential/SCI	**179,991**	**9,473**	**189,464**		**$ 51,544,898**		**$ 31,228,035**		**$ 24,689,528**	**$ 25,564,293**
SCI/LCI	**12,833**	**2,817**	**15,650**		**$ 15,808,507**		**$ 6,948,884**		**$ 5,493,931**	**$ 2,767,914**
Total	**192,824**	**12,290**	**205,114**		**$ 67,353,405**		**$ 38,176,919**		**$ 30,183,459**	**$ 28,332,208**

Net Charge Offs Benefit Under Full AMI	**$ 28,332,208**		
Net Charge Offs As Is	**$ 58,515,667**		
Net Charge Off Benefit Percentage	**48.4%**		
2012 Baseline Bad Debt Expense Budget	**$ 63,000,000**		
Bad Debt Reduction Scenario	**Projected Bad Debt**	**Benefit Amount**	**Percent Reduction**
Target Bad Debt Expense Post AMI	**$ 32,496,561**	**$ 30,503,439**	**48.4%**
Upper Band of Post AMI Bad Debt Expense	**$ 43,000,000**	**$ 20,000,000**	**26.5%**
Lower Band of Post Bad Debt Expense	**$ 26,000,000**	**$ 37,000,000**	**55.6%**

F.5 Meter Reading—Avoided Labor Costs

Business Owner and Organization / Department
Meter Reading
Background and Description of Benefit
This benefit includes the avoided O&M (not capital expense) **Labor** costs associated with reduction of the meter reading cost center. Specifically, the following labor costs are reduced and ultimately eliminated: **direct labor (full-time and temps/contractors), incentives, pension & benefits, and overtime**. Meter Reading activity levels will decline with the automation of AMI meters. Some level of residual activities will remain and assumed to be performed by the 40 meter reader inspector positions staffed (within the F&MS area) at the end of deployment. ComEd is modeling the reductions in FTE and related costs for the meter reading activity. Under agreement with its unions, ComEd will re-deploy meter readers to perform other ComEd responsibilities[91]. This benefit reflects the avoided costs of the meter reading activity. It makes no argument about the roles, responsibilities and costs associated with the activities taken up by these FTEs elsewhere in the organization. A significant aspect of these benefits is that under the current meter reading system, ComEd captures approximately 88% (on average) of all required monthly reads. This drives estimation work and has other business impacts. It may also create a negative demand response behavior (to the extent that customers do not have routine, timely availability of their actual monthly consumption). With AMI, customers will have web access to interval usage on a next-day basis. The limited cost reduction benefit here is based and scaled from the following assumptions: • 2011 activity levels for each area, based on estimated FTEs. • Increases over time of the “As Is” activity level based on system growth. • For the “As Is”, accounting for the seasonality adjustment has been factored in, whereby ComEd achieves lower and higher rates of meter reading due to season. This is an adjustment parameter in the model. • A residual floor for meter reading. This is a percent value adjustment parameter in the model. • Costs are based on 2011 salary levels for direct labor, supervisors and clerks. • Costs are based on an implied equivalent salary level for the contract labor (equal to meter readers).
Impact / Handling of Benefit - Impact on Revenue Requirements
Meter Reading cost center will be significantly impacted and lowered. **Impact to Revenue Requirements**. The reduction O&M costs, which will decrease ComEd’s revenue requirements.
Functional Requirements to Achieve Benefit
AMI system performance capable of ensuring routine availability of 30-minute peak demand and/or hourly measurement to support all peak demand and/or hourly usage tariffs (e.g., RRTP, ComDec) and reliable monthly measurement for other customers at performance levels in excess of 99% of the readings available within the billing window. (AMI system performance is often characterized around monthly billing read performance as well as other metrics such as daily, hourly and 30-minute peak demand read performance.)
Business Process Changes to Achieve Benefit

[91] While the labor strategy for installing the smart meters has not been determined, it is possible that meter readers will be offered the opportunity to install smart meters.

Business process changes will be required to ensure verification of measurement data and posting of data to customer care and billing systems to meet the expected higher routine level of dependable, reliable and accurate monthly measurement. Business processes to ensure high quality read availability, including processes to ensure network availability (field network, WAN, hosted AMI head end, MDMS, Middleware and business applications like billing). Also, the creation of a new department, AMI Operations, will occur for the primary purpose of monitoring the health of the new meter reading system from meter to CIMs and addressing performance issue on a day-to-day basis.

Benefit: Metrics and Key Assumptions

This benefit calculation is based on estimation of FTE changes due to total read requirements as the system grows. The following table depicts the read levels (total computed monthly read requirement under "As Is" and "To be". The difference will be used to drive reductions in FTE and associated FTE costs.

This information is driven by the seasonality adjustment: Probe read rate goal is 95% and demand goal is 90% - AMI would be substantially higher resulting in less billing impacts, calls to call center and complaints.

Target Read Rate Performance

- 75% for 5 months (Jan, Feb, Mar, Nov, Dec)
- 90% for 7 months (Apr – Oct)

Next, cost factors are determined for each resource.

- 2011 yearly wage factors are assumed for meter readers, supervisors, clerks
- Contract labor is assumed to be at the same cost as meter readers on a yearly basis.

Meter Readers	$45,609
Clerks	$70,248
Supervisors	$78,872
Contractors	$45,609

It is also assumed that the base resource levels for 2011 are:

Meter Readers	400.0
Clerks	37.0
Supervisors	29.0
Contractors	64.0

Additionally note that:

- Rounding is used in computing the # of FTEs.
- The number of field trips is assumed to scale with system growth. So as the ComEd system grows the # of FTEs is assumed to grow also. Another way of stating this assumption is that it is assumed that ComEd **does not experience improvements in the level of productivity** associated with meter reading over time.
- The rate of phase in of the AMI network drives the benefit. For example, when 10% of the core deployment is completed, then it is assumed that 10% of the manual meter readings are avoided.

Benefit Realization Schedule

The phase in schedule would match the deployment of smart meters.

Incremental Costs to Achieve Benefit

It will be assumed that the 40 inspectors will perform these on-going "residual" manual meters reads in addition to their inspection activity.

Benefit Calculation

Annual Direct Salary cost savings are calculated based on "As-Is" and "To-Be" comparison, and also calculated based on FTE and avg. salary values provided by ComEd. Refer to the appendix of the report for illustration of these As-Is and To-

Be values.

Benefit Realization Schedule: It would phase in as the AMI system is deployed.

Growth: This benefit would grow as the system grows.

Escalation: This benefit would increase with the rate of escalation in the value of the avoided yearly costs of the meter reading related personnel.

Pilot Findings / Results to Support Estimated Benefit

The Pilot verified the assumption that meter reading positions will be eliminated as meters are deployed at a rate of approximately one meter reader for every 10,000 meters automated. With the pilot at approximately 120,000 meters, 11 meter reader positions were reduced.

Supporting Data

Table 1 – Meter Reading Incentive and Pension & Benefit Percentages

F&MS and Meter Reading Pension and Benefits					
	METER READING			F&MS	
	Union - Meter Readers	Union - Clerks	Mgmt- E02 - E05	Union - ET & Clerks	Mgmt- E02 - E06
Total Pensions & Benefits, excl. Incentive	**45.82%**	**66.55%**	**51.87%**	**61.05%**	**54.68%**
Incentive					
AIP - Union [3]	**4.00%**	**4.00%**		**4.00%**	
AIP - Management [4]			**12.68%**		**13.52%**

NOTES
[1] Source: Based on employee data provided by P Kavanagh; excludes 30 temporary Meter Readers not eligible for benefits.
[2] Cost data as of 1/1/2011 as % of Base Pay for ComEd employees from Towers Watson 2011 ComEd Average Service Cost by Pay Band analysis
Mgmt costs have been weighted by grade level for MR & F&MS employees.
[3] Union incentive cost is applied to Base Pay plus Overtime.
[4] Management incentive cost reflects weighted payout percentage by grade level for MR & F&MS employees.

Table 2 – 2011 "As-Is" Meter Reading Budget

Budget	2011
Base Payroll	23,778
Overtime	600
Other Premiums	923
Pensions & Benefits	16,499
Payroll Taxes	-
Contracting	586
Transportation	2,588
Materials	338
Office & Postage	65
Travel/Meals	476
Functional Contracting	-
Other Expenses	91
Total	**45,943**

F.6 Meter Reading—Avoided Non-Labor Costs

Business Owner and Organization / Department
Meter Reading
Background and Description of Benefit
This benefit includes the avoided non-labor costs of the Meter Reading area, including: Transportation/Vehicles, Office & Reimbursable Expenses, and Materials
Impact / Handling of Benefit - Impact on Revenue Requirements
Customer savings are reflected in the change in revenue requirements (as a component of total revenue requirements). **Revenue Requirements** will decrease [cite specific customer charge area impact].
Functional requirements
AMI system performance capable of ensuring routine availability of 30-minute peak demand and/or hourly measurement to support all peak demand and/or hourly usage tariffs (e.g., RRTP, ComDec) and reliable monthly measurement for other customers at performance levels in excess of 99%. (AMI system performance is often characterized around monthly billing read performance as well as other metrics such as daily, hourly and 30-minute peak demand read performance.)
Business Process Changes to Achieve Benefit
Business process changes will be required to ensure verification of measurement data and posting of data to customer care and billing systems to meet the expected higher routine level of dependable, reliable and accurate monthly measurement. Integration of AMI to MDMS with appropriate verification routines and capabilities. Integration of MDMS to billing systems (e.g., CEDAR and CIMS). Business processes to ensure high quality read availability, including processes to ensure network availability (field network, WAN, hosted AMI head end, MDMS, Middleware and business applications like billing). Also, the creation of a new department, AMI Operations, will occur for the primary purpose of monitoring the health of the new meter reading system from meter to CIMs and addressing performance issue on a day-to-day basis.
Benefit: Metrics and Key Assumptions
This benefit calculation is dependent on: These 3 non-labor budget costs are decreased proportionally with the meter reading FTE counts, and similarly these non-labor costs will be eliminated upon completion of the full AMI deployment.
Benefit Realization Schedule
The phase in schedule would match the deployment of smart meters.
Incremental Costs to Achieve Benefit
N/A
How is this benefit quantified?
The non-labor costs for Meter Reading (including Transportation/Vehicles, Office & Reimbursable Expenses, and Materials) will be reduced and ultimately eliminated proportional to the reduction of Meter Readers. See the table below for the 2011 As-Is budget. *Benefit Realization Schedule*: It would phase in as the AMI system is deployed, as with MR01, delayed by 12 months. *Growth*: This benefit would grow as the system grows. *Escalation*: at Labor rate

Pilot Findings / Results to Support Estimated Benefit
The Pilot verified the assumption that meter reading positions will be eliminated as meters are deployed at a rate of approximately one meter reader for every 10,000 meters automated. With the pilot at approximately 120,000 meters, 11 meter reader positions were reduced.
Future Benefit Opportunities Not Quantifiable Today
N/A
Supporting Data

Table 2 – 2011 "As-Is" Meter Reading Budget

Budget	2011
Base Payroll	23,778
Overtime	600
Other Premiums	923
Pensions & Benefits	16,499
Payroll Taxes	-
Contracting	586
Transportation	2,588
Materials	338
Office & Postage	65
Travel/Meals	476
Functional Contracting	-
Other Expenses	91
Total	**45,943**

F.7 Meter Reading—Avoided Handheld Costs

Business Owner and Organization / Department
Meter Reading
Background and Description of Benefit
With smart meters deployed system wide, ComEd will be able to nearly eliminate the use of the handheld system used by the meter readers. A small residual number of meter readings will require the handheld solution and will be utilized by the 40 inspector positions created after full deployment. This benefit encompasses the three avoided cost items below: Avoided Maintenance of handhelds (either existing or new upgrade) Avoided Maintenance of IT Servers (HW maintenance) Avoided replacement costs of and held devices Additionally, ComEd may have a write down of any existing plant in service (if any) related to these systems (e.g., retired servers for example). ComEd will be able to realize the benefits in the following manner: • Under both the 5 year and 10 year deployment scenarios ComEd will not need to replace hand held devices because they will be available in excess as AMI meters are installed. There will be a savings avoided with replacing worn out hand held units. • Maintenance costs will decrease as the number of hand held devices in service decreases. However, as the number of handheld devices maintained decrease, the costs associated to maintaining each unit will increase slightly. There will need to be 100 hand held devices kept in service at the end of the installation period for ongoing manual meter reads. • Less IT servers will need to be maintained at steady state AMI due to the reduction in the number of hand held units necessary to support.
Impact / Handling of Benefit - Impact on Revenue Requirements
The Meter Reading and IT maintenance departments will realize cost savings associated with this avoided level of handheld utilization. **Impact to Revenue Requirements**. The reduction O&M costs and/or capital expense, which will decrease ComEd's revenue requirements. Customer savings are reflected in the change in revenue requirements (as a component of total revenue requirements).
Functional Requirements to Achieve Benefit
AMI meters are installed and reading automatically with greater than 99% efficiency. The manual meter reading system (PP4 or some other solution) will need to operate as it does today throughout the AMI deployment period, as well as during steady state.
Business Process Changes to Achieve Benefit
Meter reading foresees little change in the normal business processes necessary to support the benefits from AMI that have been estimated as part of the business case. This benefit hinges on maintaining a manual meter reading system going forward and keeping that process viable in steady state AMI deployment.
Benefit: Metrics and Key Assumptions
This benefit calculation is dependent on: • Assumed AMI deployment schedules (and retirement date of existing systems) • Software and hardware cost factors. • A software upgrade will be required in year 11 for the all AMI deployment scenarios and the As Is state. There is no opportunity to avoid this cost in the AMI deployment.

- A manual meter reading system, assumed to be PP4, will be required under all AMI and As Is scenarios so there is no opportunity to retire this system under AMI.
- The IT maintenance organization continues to support the hardware and software consistent with the 5-year and 10-year strategies
- Replacement hand held costs are approximately 20% of the yearly maintenance costs

Benefit Realization Schedule

Reduced handheld maintenance, hardware retirement, and avoided future hardware purchases:

	Year										
	1	2	3	4	5	6	7	8	9	10	Total
As Is Hand Helds	625	625	625	625	625	625	625	625	625	625	
Per Unit Cost	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	
As Is Costs	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 18,750	$ 187,500
Replacement Costs	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 3,750	$ 37,500
10 Year Deployment											
Hand Held Volumes	625	567	508	450	392	333	275	217	158	100	
Per unit cost	$ 30	$ 33	$ 37	$ 40	$ 43	$ 47	$ 50	$ 53	$ 57	$ 60	
Cost	$ 18,750	$ 18,889	$ 18,639	$ 18,000	$ 16,972	$ 15,556	$ 13,750	$ 11,556	$ 8,972	$ 6,000	$ 147,083
5 Year deployment						Total					
Hand Held Volumes	625	494	363	231	100						
Per unit cost	$ 30	$ 38	$ 45	$ 53	$ 60						
Cost	$ 18,750	$ 18,516	$ 16,313	$ 12,141	$ 6,000	$ 71,719					

5 year scenario: A savings of $115,781 in O&M maintenance costs ($187,500 – $71,719) and an avoided cost of $18,750 in capital hardware replacements.

10 year scenario: A savings of $40,417 in O&M maintenance costs ($187,500 - $147,083) and an avoided cost of $37,500 in capital hardware replacements.

Incremental Costs to Achieve Benefit

None.

Benefit Calculation

Avoided Purchases of Hand Held Units (Capital)

- Avoided purchases of hand helds are estimated at a rate of 20% of the yearly maintenance costs in the As-Is state.
- Under the 5 year deployment scenario this is $3,750 a year for 5 years for a total avoided capital cost of $18,750.
- Under the 10 year deployment scenario this is $3,750 a year for 10 years for a total avoided capital cost of $37,500.

Avoided Maintenance of IT Servers (HW maintenance)

- Quantified under IT estimates.

Avoided Maintenance of Handheld hardware

- Estimated above.

Phasing: The O&M benefits will be recognized at the time of decommissioning.

Growth: Avoided software maintenance charges will account or reflect the growth in the ComEd system.

Escalation:

- SW – Assumed to escalate at rate of other services
- HW – Assumed to escalate at rate of other products

Pilot Findings / Results to Support Estimated Benefit
The pilot demonstrated that the manual meter reading requirements are reduced in proportion to the number of smart meters deployed. The pilot learnings also suggest that a backup manual meter reading solution must be in place for meters that fail and need to be manually read until the problem is resolved.
Future Benefit Opportunities Not Quantifiable Today
A replacement to the existing PP4 system is not in scope for the AMI effort, but could provide additional savings.
Supporting Data
N/A

F.8 Field & Meter Services—Avoided Labor and Non-Labor Costs

Business Owner and Organization / Department
Field Meter Services
Background and Description of Benefit
Reduction of Labor Costs This benefit is associated with the reduction in direct Labor costs from reduced FTE headcount resulting from AMI / Smart Meter automation. Specifically, there is a reduction of direct labor (i.e., base salary, incentive, pension & benefit, overtime) in the Field and Meter Services department. Note that as part of this benefit many business processes change. This benefit is the net effect of those changes (old activities decreased and/or eliminated and new activities arising). As a result of automation, ComEd expects that the F&MS department will decline in total required Field Tech FTE slightly, from the current 2011 level of 212 to a future level of 145 once automation is full deployed. The break-down of these FTE counts is included further below in Table 2. It is worth noting that while there is an estimated change in the reduction of Field Tech FTE, there is no estimated reduction in Management, Clerical, or Mechanical Tech FTE. This benefit includes field installation work. It is very important to recognize that some of this work is a capital expenditure and needs to be accounted for appropriately. **Reduction of Transportation Costs (Non-Labor)** In addition to a reduction in the direct labor costs, there is also an estimated reduction in transportation costs (non-labor). This benefit is modeled and estimated to be proportional to the reduction of labor costs.
Impact / Handling of Benefit - Impact on Revenue Requirements
Customer savings are reflected in the change in revenue requirements (as a component of total revenue requirements). **Revenue Requirements** will decrease [cite specific customer charge area impact].
Functional Requirements to Achieve Benefit
These benefits are dependent upon the deployment of the AMI meters, along with the basic AMI functionality of the remote disconnect / reconnect switch. See Table 1 below for the list and count of F&MS field work activities in the "As-Is" and "To-Be" scenarios.
Business Process Changes to Achieve Benefit
There will be a number of new business rules for the F&MS area as some of the current activities will be significantly reduced, and in some cases eliminated, while conversely there will be net new activities driven by the implementation of the new AMI meters. See Table 1 below for the list and count of F&MS field work activities in the "As-Is" and "To-Be" scenarios. Following full deployment of AMI, additional processes and FTEs will be required to inspect the meters in the field and verify meter readings. This is anticipated to require approximately 40 FTEs with similar job responsibilities and skill sets of the meter reading classification.
Business Process Changes to Achieve Benefit
There will be numerous business process changes necessary to incorporate the new technology. F&MS will inherit numerous new processes associated with automation. See Appendix for a detailed table of expected "As Is" and "To Be" F&MS activities and definitions.
Benefit: Metrics and Key Assumptions
This benefit calculation is dependent on the following metrics and key assumptions: • Note that the initial installation and deployment costs to transition to AMI meters are *not* included in the FTEs for F&MS. • The Incentive benefits are calculated specifically for this area (as opposed to using the general ComEd system-wide

percentages), and are included in the table below • The model differentiates O&M vs. Capital costs of the "To-Be" benefits based on the 2017 Steady-State budget • During deployment, FTE reductions (and therefore Budget amounts) are ramped proportional to the deployment of AMI meters. • In the on-going "To-Be" scenario, FTE counts are increased year-over-year to accommodate the estimated 0.5% system growth. Similarly, Budget amounts are also increased to account for financial escalation year-over-year. These annual percentage increases were used consistently throughout the model based on values provided by the ComEd Finance Team.
Benefit Realization Schedule
The benefit realization schedule would match the deployment of smart meters.
Incremental Costs to Achieve Benefit
This benefit is the net change in FTE and ultimately in Budget (tables included below) going from the 2011 "As-Is" scenario to the 2017 Steady-State "To-Be" scenario. While some activity levels have increased and others have decreased, the net affect is an overall reduction.
Benefit Calculation
The following three tables ("As-Is" FTE and Budget, "To-Be" FTE and Budget, and Difference FTE and Budget) shows the value and approach used to compute this benefit. The FTEs increase over time due to system growth. Direct labor yearly cost factors are used to translate the FTE changes into dollar impacts on nominal real terms. (Escalation is adjusted elsewhere). The table shows annual values from 2011 through 2017. NOTE: Due to rounding and averaging of numbers, there are noted discrepancies between these "modeled" values and those actual budget values provided by the F&MS team. These deltas will be reviewed by the team and addressed as necessary to ensure the benefits are being modeled effectively. *Benefit Realization Schedule*: These benefits would phase in as the AMI system is deployed. *Growth*: This benefit would grow as the system grows. *Escalation*: at Labor rate
Pilot Findings / Results to Support Estimated Benefit
The Pilot helped ComEd identify the new set of F&MS related activities associated with AMI and to estimate the volume that would be realized with a full deployment. These include reduction in orders associated only with the older mechanical meters such as "Stuck Meter Orders", and are offset by an increase in AMI driven theft investigation orders.
Supporting Data
See tables on subsequent pages.

Table 1 – "As-Is" and "To-Be" F&MS Activities by Year

FMS Activity	As-Is (2011)	To-Be Steady State (2017)
Regulatory	**47,701**	**60,583**
Periodics - Single Phase	15,580	20,000
Periodics - Three Phase	22,420	33,634
Periodics - Total	**38,000**	**53,634**
Random Samples	4,075	4,250
Aux Maintenance	2,546	2,699
Com Decs	1,280	0
RRTP	1,800	0
Revenue Work	**479,480**	**139,298**
Residential Cuts	106,750	9,473
Commercial Cuts	11,250	2,817
Cut Ins	74,860	9,507
Connects	87,550	6,566
New Business Sets	20,149	21,358
New Business CMO's	7,167	7,597
Exchange/CMO	33,000	34,980
Meter Investigation	38,254	25,000
Meter Inv - Closed Loop	9,000	1,000
CCM (Consumption on Cut Meter)	8,000	1,000
Theft Field Originated	6,500	1,000
Theft / Rev Protection	3,000	1,500
CIM (Consumption Inactive Meter)	49,000	7,500
Stuck Meter	15,000	0
CCI (Commercial Compliance Inv)	10,000	10,000
Customer Maintenance	**21,710**	**22,309**
AMR Exchanges	275	0
High Bill	2,195	2,200
Mixed Meter	2,750	3,000
MI Irregular Condition	6,900	7,000
Rate Check	940	996
Remove	2,600	2,700
Repair	6,050	6,413
AMI Meters	**0**	**86,200**
AMI Meter Investigations (Non-Theft Events & A	0	40,000
AMI Theft - unreachable after disconnect for n	0	19,000
AMI Theft - unreachable after move-out discon	0	24,000
AMI Theft - Voltage on load side cut meter	0	2,000
AMI Theft - Reverse Energy	0	1,200
AMI Theft - Other	0	0
Sub-Total	**548,892**	**308,391**
% Reduction		**43.8%**
AMI Inspection and Reads	**0**	**1,070,134**
AMI Safety Inspections (periodic)	0	1,000,000
AMI Safety Inspections (based on 30 days with	0	31,134
Manual meter readings (consecutive estimates	0	33,000
Manual meter readings / probes (complex rate	0	6,000
TOTAL	**548,892**	**1,378,525**

Table 2 – "As-Is" and "To-Be" F&MS FTE Headcount

Mgmt / Union	Role	As-Is (2011)	Notes	To-Be (2017)
Mgmt	RT-Indirect-Ind Contrib E2	20	Stay same in 2016	20
Mgmt	RT-Ind Contrib E3-Supervisor-D	19	Stay same in 2016	19
Mgmt	RT-Indirect-Ind Contrib E4	4	Stay same in 2016	4
Mgmt	RT-Indirect-Director E6	1	Stay same in 2016	1
Union - Clerical	RT-Clerical	22	Stay same in 2016	22
Union - Tech	RT-Mechanic Electronic	3	Stay same in 2016	3
Union - Tech	RT-Mechanic Meter Equipment	1	Stay same in 2016	1
Union - Tech	RT-Meter Mechanic Special	6	Stay same in 2016	6
Union - Field Techs	RT-Senior Energy Technician	110	Adj for 2016	72
Union - Field Techs	RT-Energy Technician	95	Adj for 2016	67
Union - Field Techs	RT-Primary Energy Technician	7	Adj for 2016	6
Union - MR	RT-Meter Reader 99	32	Adj for 2016	40
		320		**261**

Table 3 - “As-Is” and “To-Be” F&MS Budget

"As-Is" 2011 Budget (in $1,000's)			"To-Be" 2017 Budget (in $1,000's)		
O&M					
Base Payroll		19,818	Base Payroll		15,077
Overtime		430	Overtime		430
Other Premiums		668	Other Premiums		211
Staff Augmentation		192	Staff Augmentation		-
Pensions & Benefits		15,019	Pensions & Benefits		11,836
Contracting:			Contracting:		
	Contracting - Ops	902		*Contracting - Ops*	588
	Contracting - NonOps	132		*Contracting - NonOps*	132
	Contracting - Outsourced	139		*Contracting - Outsourced*	139
Transportation		2,228	Transportation		1,563
Materials		1,299	Materials		1,299
Office & Postage		34	Office & Postage		34
Travel/Meals		268	Travel/Meals		268
Functional Contracting		-	Functional Contracting		-
Other Expenses		86	Other Expenses		86
Bad Debt		-	Bad Debt		-
	Subtotal	**41,215**		***Subtotal***	**31,663**
Capital					
Base Payroll		4,289	Base Payroll		4,062
Overtime		120	Overtime		120
Other Premiums		28	Other Premiums		-
Staff Augmentation		-	Staff Augmentation		-
Pensions & Benefits		3,255	Pensions & Benefits		3,183
Payroll Taxes		410	Payroll Taxes		377
Contracting:			Contracting:		
	Contracting - Ops	-		*Contracting - Ops*	-
	Contracting - NonOps	-		*Contracting - NonOps*	-
	Contracting - Outsourced	-		*Contracting - Outsourced*	-
Transportation		470	Transportation		427
Materials		7,649	Materials		10,097
Office & Postage		4	Office & Postage		4
Travel/Meals		11	Travel/Meals		11
Functional Contracting		-	Functional Contracting		-
Other Expenses		110	Other Expenses		110
Bad Debt		-	Bad Debt		-
	Subtotal	**16,347**		***Subtotal***	**18,391**
	TOTAL O&M and Capital	**57,562**			**50,054**

Capital/O&M Split 2011 Budget		Capital/O&M Split 2016 Budget	
	Budget		**Budget**
Base+OT+Payroll Premiums O&M	82.5%	Base+OT+Payroll Premiums O&M	79.0%

Table 4 – F&MS Incentive and Pension & Benefits

F&MS and Meter Reading Pension and Benefits

	METER READING			F&MS	
	Union - Meter Readers	Union - Clerks	Mgmt- E02 - E05	Union - ET & Clerks	Mgmt- E02 - E06
Total Pensions & Benefits, excl. Incentive	**45.82%**	**66.55%**	**51.87%**	**61.05%**	**54.68%**
Incentive					
AIP - Union [3]	**4.00%**	**4.00%**		**4.00%**	
AIP - Management [4]			**12.68%**		**13.52%**

NOTES

[1] Source: Based on employee data provided by P Kavanagh; excludes 30 temporary Meter Readers not eligible for benefits.

[2] Cost data as of 1/1/2011 as % of Base Pay for ComEd employees from Towers Watson 2011 ComEd Average Service Cost by Pay Band analysis
Mgmt costs have been weighted by grade level for MR & F&MS employees.

[3] Union incentive cost is applied to Base Pay plus Overtime.

[4] Management incentive cost reflects weighted payout percentage by grade level for MR & F&MS employees.

F.9 Field and Meter Services—Avoided AMR Costs

Business Owner and Organization / Department
Field & Meter Services (F&MS)
Background and Description of Benefit
ComEd will be able to substitute the AMI capability for the currently deployed AMR solutions. ComEd has three legacy AMI solutions today each using different forms of communication: • MV90 utilizing dial up and CDMA • Utilizing two way paging and GPRS • Meters (mesh network topology for communications). This benefit description here is for four separate model line items: • Avoided communication costs • Avoided HW purchase • Avoided SW maintenance Deployment of the substitute AMI capability is assumed: • The dispersion of these units is assumed to be across the service territory. • The model assumes that one specific year is targeted for replacement, towards the end of the deployment cycle: - 5 yr – TBD - 10 yr -- TBD Reduction in the maintenance of telephone, paging and wireless accounts and circuits. Reduction in troubleshooting these circuits. Reduction in 3rd party fees associated with the back-office IT infrastructure, software and licensing as well as operations and maintenance.
Impact / Handling of Benefit - Impact on Revenue Requirements
The F&MS cost center will be impacted and lowered. **This benefit will result in a reduction to Revenue Requirements**. The reduction O&M costs and/or capital expense, which will decrease ComEd's revenue requirements.
Functional Requirements to Achieve Benefit
AMI system capable of meeting the same level of measurement robustness as the replaced AMR system. Hourly measurement delivered on a daily basis at a 99%+ level of reliability is assumed.
Business Process Changes to Achieve Benefit
Current AMR meters are used for Energy Insights web application for customer monitoring (~ 1,000 customers). Currently, the ~700 Transdata meters read by MV90 are monitored by SCADA and Energy Acquisition. Meters give reading to the above groups through the required DTO and DNP communications. Since the cost/benefit analysis only considers retail metering, these will be considered out-of-scope.
Benefit: Metrics and Key Assumptions
This benefit calculation is dependent on the following metrics and key assumptions: • # of installed AMR by type - MV90 meters: ▪ Landlines – 961 <customer provided>

- Cell phone modems - 2206
- MAS meters:
- Collectors and Rex – 691
- TMS meters:
  - Paging – 2222

- Costs of meter types:
  - Landline AMR
    - ~ $195.00
  - Cell phone AMR
    - (Trillant & Verizon CDMA) ~ $695.00 <*no longer purchased*>
  - MAS (Rex vs. Collector)
    - REX (non disconnect) ~ $90.00
    - REX (with disconnect) ~ $130.00
    - Collector ~ $800.00
  - AMR GPRS
    - ~ $541.00 with external antenna
    - ~ $446.00 with internal antenna
- Assumed deployment date (and retirement date of existing systems)
- 3rd party service fees
  - Fees for AMR meter with Verizon communications:
    - Monthly: $32k
    - $5 per meter plus telecom overages.
  - Fees for Vendor Management:
    - Monthly: $51k
    - $8 per meter for all AMR devices plus taxes
  - Total monthly fees for Vendor management: $83k
- There is no assumption in the reduction in the field visits associated with the maintenance of these meters.
- There is no estimated write-down of any existing plant in service related to these systems.

Benefit Realization Schedule

The phase in schedule is set at specific dates within the deployment cycle. For 5 year, assumed deployment cycle is 2015. For 10 year, assumed deployment cycle is 2015.

Incremental Costs to Achieve Benefit

None identified.

Benefit Calculation

This benefit calculation is dependent on:

- # of installed AMR by type
- Costs of leased or other circuits
- Assumed deployment date (and retirement date of existing systems)
- Software and hardware cost factors.
- Costs of meter types:
    - Landline AMR
        - ~ $195.00
    - Cell phone AMR
        - ~ $695.00 *<no longer purchased>*
    - Rex vs. Collector
        - REX (non disconnect) ~ $90.00
        - REX (with disconnect) ~ $130.00
        - Collector ~ $800.00
    - AMR GPRS
        - ~ $541.00 with external antenna
        - ~ $446.00 with internal antenna
- 3rd party service fees
    - Fees for AMR meter with Verizon communications:
        - Monthly: $32k
        - $5 per meter plus telecom overages.
    - Fees for Vendor Management:
        - Monthly: $51k
        - $8 per meter for all AMR devices plus taxes
    - Total monthly fees for Vendor management: $83k

Benefit Realization Schedule: The O&M benefits will be recognized at the time of decommissioning.

Growth: The total number of AMR accounts is assumed to be constant over the "As Is" planning horizon.

Escalation: This benefit would increase with the rate of escalation in the value of the avoided costs (e.g., capital, telecom costs, etc.).

- SW – Assumed to escalate at rate of other services
- HW – Assumed to escalate at rate of other products
- Teleco lines – Assumed to escalate at rate of other services

Pilot Findings / Results to Support Estimated Benefit

Meter reading rates achieved within the pilot have met or exceeded the read rates typically seen with the existing AMR solution, verifying that this approach would benefit the company and the consumer.

Supporting Data

F.10 Outage Management—Single Lights Out and Major Storms

Benefit label (for model)	Benefit name
DO-01 and DO-02	Avoided costs associated with two outage-related benefits: Avoided Single Lights Out and Improved efficiency during major storms.
Business Owner and Organization / Department	
Distribution System Operations	
Background and Description of Benefit	
There are two major benefits associated with improvements in outage management that result from the availability of power status information from the AMI system: **Avoided Single Lights Out** - It is anticipated that AMI will provide the ability to indicate a quasi real-time outage status for the majority of 1ph-metered customers. Because of this, it is anticipated that ComEd will experience fewer "OK On Arrival" occurrences (i.e. customers were already restored earlier on a different outage ticket) and will not need to send a first responder to the field needlessly to check status. ComEd will now be able to ascertain real-time power status via an AMI indication which will more accurately reflect the current state of restoration activity and allows resources to be utilized more efficiently. This will also reduce costs for "call ahead's". **Improved Efficiency During Storms** - It is anticipated that AMI will provide the ability to indicate a quasi real-time outage status for the majority of 1ph-metered customers. This AMI indication can more accurately reflect current outages and allow resources to be routed more efficiently in certain instances. Therefore, decreasing the time allotted for storm cleanup and saving in overtime and contractor expenditures. The benefits ascribable to Smart Metering include: ▪ The ability to query the smart meter on demand to verify power status. ▪ The ability to receive and interrogate the smart meter system for outage information ▪ Reduction in truck rolls to respond to single light out complaints. ▪ Reduction in phone calls to customers, both automated and manual, associated with single light out outages. ▪ Reduction in phone calls from customers associated with single light out outages.	
Impact / Handling of Benefit - Impact on Revenue Requirements	
The beneficiaries include Field Service that will see efficiencies due to reduced trucks rolls and there will be fewer outbound phone calls – both related to the single lights out benefit. For improvements due to storm restoration efficiency, beneficiaries will include field services, Distribution Operations, and support organizations that mobilize during storms. To the extent that costs are saved, these costs are a form of utility O&M savings.	
Functional Requirements to Achieve Benefit	
The new smart meter will provide indication of an outage restoration event. These restorations will be transmitted through the AMI network to the head-end application and may be provided to the OMS application Reliable delivery by the AMI system of restoration notifications is required. It is anticipated that for large outage events, the system will not immediately deliver 100% of all restoration event information, but the ComEd Pilot demonstrated that restoration information can be reliably received with acceptable time lag to provide useful information for Dispatchers to act upon.	
Business Process Changes to Achieve Benefit	

New business processes will need to be created to incorporate the smart meter outage information that is available from the AMI system into ComEd business processes and the OMS application.

Benefit: Metrics and Key Assumptions

The key driver of the benefits are:

1. A reduction in truck rolls and outbound phone calls associated with improved response to single light out complaints.
2. The improvements in storm response will impact direct ComEd overtime labor costs, contractor costs, and mutual aid costs. A reduction in the overall time duration of storm events will result in a decrease in organizational impact and improved organizational efficiency.

The benefit calculations are dependent on:

1. The single no light benefit is based on 30% reduction in Field Trips to Single Customer High Voltage (152) and Low Voltage (4,326) Calls as well as single all-out and part-out OK on Arrivals (894). The OK on Arrival benefit assumes that 20% of the all-out and part-out OK on Arrivals were already confirmed as having power due to call aheads (1,118 total all-out and part-out OK on Arrivals * 80% = 894). Data is 4 year annual average (2007 to 2010).
2. As a benchmark value, a mid-west utility avoided 5,700 "single lights out" trips/year out of ~16k total "single lights out" trips. KCPL avoided ~2,100 trips/year out of a total of 6,500 trips. PECO data: June '04 to Nov '04: 11,400 jobs analyzed using auto ping of which 5,800 jobs (51%) came back with "power on" status and of those 1,774 (16%) were auto-cancelled (From 2003 study).
3. Outbound call reduction benefit is based on $0.60 per call * (5,673 call-aheads per year and 137,446 restoration confirmation call-backs), as there will be no operational need for restoration call-backs at 100% AMI implementation. Data is 3 year annual average (2008 to 2010).
4. For reportable storms, ComEd data 2008 through 2010 indicates the total number of outages dispatched = 30770, and the total number of outages dispatched and found to be "OK On Arrival" = 3509. So, the anticipated % reduction in outage ticket volume due to the elimination of "OK on Arrivals" = 11% and is applied to incremental C&M OT and Contractor expenditures.
5. As a benchmark value, another mid-west utility estimated that 7% of its trips were eliminated during Level 2 and Level 3 storms following the implementation of AMR.
6. As a benchmark value, During Hurricane Isabel (Sept 03): PECO eliminated 950 out of 2,400 still lights out trips (40%)
7. As a benchmark value, PECO data: June '04 to Nov '04: 11,400 jobs analyzed using auto ping of which 1,774 jobs were auto-cancelled (16%).

Impact on Electricity Delivery Reliability

No substantial impact to reliability.

Benefit Realization Schedule

The phasing of the benefits are based on the rollout of the smart meters, with the current pilot functionality providing for the efficiency improvements related to both the single customer outages and major storm restoration benefits.

Incremental Costs to Achieve Benefit

To achieve both quantified outage benefits, there will need to be business process changes to allow for the AMI meter power status information to be incorporated into the process flow. However, no significant system or IT enhancements are required to support these changes.

Benefit Calculation

Approximately 5,372 trips to the field would be avoided each year with AMI. This equates to about an hour of over time for each trip at a rate of $66.34 per hour. Also avoided would be costs associated to 5,673 call ahead and 137,446 restoration confirmation automated outbound calls at about $0.60 per call. This is a total savings of $442,265 for the single lights out and automated phone call benefits.

Large scale storm efficiencies result in approximately 11% reduction in labor during large storms. This was based on industry benchmarking and improvements in the OMS system. When applied to a 3 year average (2008 to 2010) of $14,676,745 ComEd employee overtime and $10,964,064 contractor overtime, this results in a savings of approximately $2,820,489.

Benefit Realization Schedule: It would phase in as the AMI system is deployed but are further dependent on business process changes.

Growth: This benefit would grow as the system grows, because the avoided truck rolls due to voltage and partial/full no lights is directly proportional to total meter count. Also the scale and impact of large storm outage events is proportional to total customers with an installed smart meter.

Escalation: This benefit would increase with the rate of escalation in the value of the cost of the avoided field truck roll or storm response labor.

Pilot Findings / Results to Support Estimated Benefit

The AMI pilot system allowed for the validation that the system is able to provide outage notification and outage restoration information from the AMI solution. While the AMI system was not directly connected to the OMS in the pilot, the performance of the outage events was monitored and demonstrated to be sufficient to provide the capabilities envisioned in this benefit.

There were storms in the pilot area that were utilized to specifically validate the single lights out benefits, by avoiding unnecessary truck rolls.

On eight (8) different dates, ComEd “pinged” meters at end of storms to confirm status of single outage tickets. **272 out of 359 customers** were confirmed to have power and therefore the outage ticket could be closed.

	21-Jun	22-Jun	24-Jun	25-Jun	24-Jul	4-Aug	26-Oct	28-Oct	Totals
# of Smart Meters Pinged	78	48	121	19	65	12	6	10	359
Meter has power	60	35	93	13	50	10	6	5	272
Meter has no power	18	13	28	6	15	2	0	5	87
% of Meters with Power	**77%**	**73%**	**77%**	**68%**	**77%**	**83%**	**100%**	**50%**	**76%**

Future Benefit Opportunities Not Quantifiable Today

ComEd may have additional opportunities to use the power status information from the AMI meters to allow ComEd call center representatives and the VRU (Voice Response Unit) to verify power status at the time of a customer call and eliminate initial invalid outage reports.

Also, further integration of the AMI system in the future with more function-rich versions of an OMS will bring additional customer benefits and operational efficiencies.

Supporting Data

F.11 Billing—Reduction of Required FTE

Benefit label (for model)	**Benefit name**
BI-01, BI-02, BI-03	BI-01-03 Billing

Business Owner and Organization / Department
Billing
Background and Description of Benefit
AMI will affect the Billing activities by increasing the volume and quality of actual meter reads, and thus reducing the volume of meter reading and system billing exceptions that occur currently as a result of missing or incorrect meter reads. The AMI system will provide higher performance for monthly reads, estimated at 99.5% average meter read performance. As a result, there will be significantly fewer estimated bills as described above Currently without AMI, system-wide meter reading performance across the ComEd service territory is approximately 88%. As a result, 12% of the monthly bills are generated based on an estimated reading that is automatically generated within the billing system, resulting in a relatively large volume of exceptions and cancel/rebill scenarios that require billing clerks to manually resolve or work in order to generate and distribute an accurate and/or corrected invoice. Described below, the benefits estimated are directly associated with a reduction in FTE resources, specifically billing clerks, as this manual work and resolution of billing orders will not be required at the same level as today. This benefit is strictly from the installation of AMI meters.
Impact / Handling of Benefit - Impact on Revenue Requirements
This benefit reduces ComEd’s costs to serve its customers. Customer savings are reflected in the change in revenue requirements (as a component of total revenue requirements).
Functional Requirements to Achieve Benefit
The core functional requirement or system capability that is driving this benefit is the automation of the meter reading process to provide near real-time meter reads from the meter through the AMI network and ultimately into the ComEd billing system. In addition, system capabilities will be developed and delivered in order to drive process efficiencies in the resolution of the remaining billing orders that continue to exist under the new AMI architecture. This can be accomplished through user integration with the AMI data through the MDM or other system application that will enable the billing clerk to request and receive the relevant AMI data required to generate a customer bill.
Business Process Changes to Achieve Benefit
The Billing clerks would need to be trained on the new applications in order to properly bill the customer. Tools currently used during the AMI Pilot are MDM, AMI CvCel and potentially UIQ. The Billing engine would remain the same, so no changes in CIMS just the methods of getting the data into CIMS would change.
Benefit: Metrics and Key Assumptions
o It is assumed that there will be a FTE reduction of billing clerks, both residential and commercial bill clerks and one management person. o See below for metrics as well as the benefit calculation.

Benefit Realization Schedule
The phase-in schedule will be based on the outcome of the full deployment schedule. This assumes that issues encountered and addressed during the pilot will not resurface. Enhancements must be sustainable throughout implementation. Based on these assumptions benefits should be achieved within 1 year or less, through attrition or other viable re-staffing options.
Incremental Costs to Achieve Benefit
There are no incremental costs estimated to achieve these billing benefits (reduction of FTE).
Benefit Calculation

<u>**Delayed Bills for Commercial and Residential**</u>
o Currently 34 FTE's needed to work Delayed Billing Inflow each day.
o These FTE complete 403,200 orders per year (1,600 orders per business day)
o Estimated reduction of 56% of these orders upon FULL and successful implementation
o Steady state annual inflow = 177,408 (44% of current order volumes)
o This results in a reduction of 15 FTE.
o Direct Salary and P&B per Billing Clerk:
    o Direct Salary: $80,808
    o P&B: $61,399
o Total savings for 15 FTE = 15 X $142,207 = $2,133,105
<u>**Management**</u>
o Based on FTE reductions we would eliminate 1 supervisor position.
o Direct Salary and P&B per Mgmt FTE:
    • Direct Salary: $86,590
    • P&B: $65,792
o Total savings for 1 Mgmt FTE = $152,382
<u>**Overtime**</u>
o 2011 (As-Is) Overtime Budget = $745,600
o Assumption: Overtime will decrease proportional to reduction in Billing Clerks (15 / 57) = 26.4%
o Steady State (To-Be) Overtime Budget = $745,600 X (1-.264) = $548,762
o Benefit = $745,600 X .264 = $196,838

Pilot Findings / Results to Support Estimated Benefit
Inside the AMI Pilot footprint, ComEd is billing 99.6% of the 112K accounts with in the billing window in 2011. Outside the footprint, ComEd is billing 99.1% of the 3.8M accounts with in the billing window in 2011. There have been times throughout the pilot where the inflow of unbilled AMI accounts was higher due to multiple issues found when conducting the pilot. The issues identified during the pilot has helped ComEd identify and make the necessary changes in the following applications: MDM, VEE Logic in MDM, Cedar, CvCel, Interfaces back into our billing system, completion of change meter orders and constant issues. These changes have driven down that inflow to current levels.
Future Benefit Opportunities Not Quantifiable Today
TBD
Supporting Data
See above for estimated benefits.

F.12 Call Center—Reduction in Required FTE

Benefit label (for model)	Benefit name
CC_Various	Call Center Reductions

Business Owner and Organization / Department

Call Center

Background and Description of Benefit

Call Center interacts with a wide range of customer inquiries, from outage to billing. AMI will affect the Call Center activity levels. ComEd expects call center activity to increase during the first year of the deployment period, and then return to a steady state level (with reductions noted in this analysis) over time. Initially, the types and volumes of calls may increase due to AMI actions related to a variety of deployment and post-deployment reasons: installation work, hard to access appointment scheduling issues, disconnection and reconnection steps for non-pay customers, new connection processes for new customers, etc. It is expected (through benchmarking with other utilities) that after the fist year of deployment the call center will adapt to the new types of calls and handle them more efficiently.

The basic premises ComEd assumes for the Call Center steady state call volumes are:

- An increase in the meter read rate will decrease calls to agents associated with bill questions and complaints. In addition, during outages a small benefit is expected to be realized in status related outages as restoration efforts will improve.
- During the first year of deployment, the Call Center expects to see an increase in call handling times related to the learning curve for Customer Service Representatives.
- Consolidation (2 to 1 locations) of call centers in the future will have no impact to incoming call volume
- Average speed to address call inquiry will not change as a result of AMI. The AMI technology has the capability to provide the CSR with interval level usage data to assist in answering high bill calls and with other discussions, but no reduction in call time has been modeled because of lack of data.
- "Energy Advisor" types of calls will be new to the Call Center and will offset some of the call reductions realized by AMI

An increase in credit related disconnections will increase the volume of calls to the call center

- Credit-related activities, as ComEd uses the disconnect capability to perform disconnects for non-paying customers, will increase call volumes to agents in the call center.

Impact / Handling of Benefit - Impact on Revenue Requirements

This benefit reduces ComEd's costs to serve its customers by reducing the overall volume of calls that agents must answer.

Customer savings are reflected in the change in revenue requirements (as a component of total revenue requirements).

Functional Requirements to Achieve Benefit

The functional requirements necessary to realize the call center benefits are those that are needed to support consistent meter reading and improved outage verification.

Business Process Changes to Achieve Benefit
The call center foresees little change in the normal business processes necessary to support the benefits from AMI that have been estimated as part of the business case. More savings could be realized in the future as additional tools become available to the CSR to assist in answering the customers 'questions as well as providing guidance on how to reduce usage through web site tools, possibly new rates and in home devices.
Benefit: Metrics and Key Assumptions
It is assumed that there is a small reduction in headcount costs associated with this benefit. ComEd is assuming that in the steady state (10 yr period), a reduction in approximately 481,939 calls due to improved meter reading rates will be partially offset by an increase in 84,000 calls as a result of increased credit activity and an additional 380,000 calls of a new "Energy Advisor" nature. This equates to approximately $124k dollars in savings through 1 FTE reduction, including pensions and benefits at 2011 rates. The first year of installation will see an increase in handling time as the call center learns to handle the new call types, which will be offset by the benefits of the AMI system. No benefits are expected in the first year of installation, but each subsequent year the benefits will follow the meter installation rate.
Impact on Electricity Delivery Reliability
No impact reliability.
Benefit Realization Schedule
The phase in schedule would match the deployment of smart meters. Benefit realization is expected to be realized within 1 year of deployment based on information from other companies (Pacific Corp, Mid-American and Alliant) who have installed AMR or AMI technology.
Incremental Costs to Achieve Benefit
N/a.
Benefit Calculation
A projected 52,289 calls will be reduced as a result of the improvements in outage dispatching. An estimated 425,650 calls will be reduced as a result of improved meter read rates. This will be offset with an increase in 84,000 calls related to the additional service disconnections over current activities, assuming 1 call per service disconnection for non-payment under an AMI environment. This will be offset in an increase in "Energy Advisor" calls or calls regarding the capabilities of the smart meter. It is estimated that 10% of the service territory will call to ask questions of this nature each year, adding a total of 380,000 new calls to the call center. This results in a total call reduction of 17,939 which equates to approximately 1 full time FTE of savings. One fully loaded full time CSR costs approximately $124,503.
Pilot Findings / Results to Support Estimated Benefit
For the Pilot ComEd trained seven (7) CSRs for dedicated effort related to the AMI deployment and operation. This represented an investment of $508,000, or 2% of the total Call Center budget. A customer experience study is being performed to understand how customer's responded to the pilot, including experience with any calls to ComEd.

Future Benefit Opportunities Not Quantifiable Today
Beyond the benefits quantified here, ComEd will need to determine the specific opportunities for the AMI-system to manage customer interactions and call volumes. There will be opportunities to determine the specific capabilities with which ComEd wishes to provision the CSR in the future. Examples include: ▪ Hourly measurement profile data from the MDM or other system of record ▪ Peak usage information on a daily basis. ▪ Analysis of usage patterns ▪ Various flags which with meter might generate (like voltage, outage restoration messages or power loss messages) ▪ "Over the air" ping of the meter to if the customer's outage complaint is related to the meter or to the customer premise (customer load side).
Supporting Data
The earlier ComEd business case assumed some improvement in productivity due to AMI and a reduction in several FTEs within the call Center function. Approximately $2 million in cost reduction was estimated. Also the earlier work did not consider new call volumes associated with some AMI-driven processes related to credit. Benchmarking was performed with Pacific Corp, Mid-American and Alliant to better understand the impact of AMI on call center operations.

Appendix G: High Rise Proof of Concept

During the stakeholder workshops, discussions took place concerning the inclusion of high rise buildings in the Pilot. As part of those discussions, ComEd shared lessons gained through prior smart metering work on the difficulty of establishing and maintaining reliable RF communications into and out of high rise buildings. This challenge is attributed to at least a couple of reasons: locations of the meters within the building and the building material construction. ComEd recommended limiting the pilot scope to a proof of concept (PoC) to assess the performance of the mesh RF technology to deliver meter usage data.

The initial objective of the PoC was to test the operational performance of the AMI technology in high rise structures encompassing approximately two to four buildings and including a total of approximately 500 meters. The AMI technology was to be tested on how reliably it delivers data to and from the AMI head-end software and the meter. The test would target "typical" high rise environments, excluding the easiest and the hardest physical environments. All the meters in the buildings would be part of the test.

In order to meet the Proof of Concept objective, ComEd defined the following eight criteria which would guide in the determination of which buildings to select as part of the PoC.

Table G.1 High Rise Proof of Concept Selection Criteria

"Must Have's"	Rationale
Multi-story building in dense environment. 20-50 floors.	Test a vertical mesh in typical loop environment
Meters located on multiple floors throughout the building	Test a vertical mesh
Mix of single phase and three phase meters	Test multiple meter types in a mesh
One or more meters located below grade	Typical configuration with high rises
Buildings adjacent to or across the street from each other	Test horizontal mesh formation
Buildings where sidewalk vault or placement of an AP will be acceptable to building owner	Avoid deployment delays due to protracted negotiations with building owners
No existing AMR meters in the building	Don't want to remove working AMR solutions, nor create an AMR/AMI hybrid solution
Avoid buildings with current meter work in progress	Complications or delays could result with multiple projects

Since there is no readily available database source for identifying buildings that meet these defined criteria, the following steps were employed:

Step 1: Conduct street side walk-downs to identify several candidate clusters based on:

- Density of tall buildings
- Buildings of appropriate height
- Buildings adjacent to each other

As a result of Step 1, ten (10) clusters of 45 buildings were identified.

Step 2: Evaluate and remove potential buildings based on the following criteria:

- On-going meter work
- Small number of meters
- Have AMR meters
- Meter information not readily available
- Input from ComEd Large Customer Services account managers

As a result of Step 2, five (5) clusters of 11 buildings remained.

Step 3: ComEd and the AMI vendor RF expert conducted internal building walk-downs to assess technical viability or non-standard design issues. Potential buildings were removed from the target population based on the location of the meter in one of the following areas:

- More than one basement level below street level
- In middle of basement surrounded by switchgear w/no RF path out
- On the wrong side of building relative to adjacent building under consideration

As a result of Step 3, two (2) clusters of four (4) buildings remained.

Step 4: Identify available utility pole line for hanging Access Point.

After the four steps were completed, the remaining two buildings selected for the proof of concept were 150 N Wacker and 155 N Wacker. ComEd account managers approached the two property managers to obtain their participation in the test. This was a key step since ComEd was unsure how well the technology would work and the need to deploy network equipment in other parts of the building could be required.

G.1 Meter and Network Installation

Network

The solution required the deployment of two Access Points and two Relays. One of the AP's was installed on a utility pole and one was installed in 155 N. Wacker. Both of the Relays were installed in 155 N. Wacker. The network equipment installed in the building required 120 volts, requiring minor work to establish safe and reliable power connection.

Meters

A total of 217 smart meters were installed: 126 meters in 155 N Wacker and 91 meters in 150 N Wacker. Installation was scheduled over two work days with one day for each building. The meters at 155 N Wacker were installed on a Saturday at the building owner's request. Many of the meter rooms required access through tenant space, and the building owner was sensitive to the potential disruption resulting from workers and material entering and leaving the space.

Network Connectivity

Both buildings have successfully formed internal vertical mesh networks and have established network connectivity back to ComEd's head-end operating system.

G.2 Operating Results

Once the meter exchanges were completed in ComEd's back office systems and the connectivity was established between ComEd and the two buildings, the meter reading success rate was slightly better than the overall pilot system performance. Table 11.2 shows the read success rate of the high rise buildings at 99.9%, compared with the total pilot system of 99.2%. ComEd continues to work with the AMI vendor to enhance the reliability of the system through establishing a horizontal mesh connecting the two buildings. If this can be established, then both buildings will have a second path back to ComEd in the event that connectivity to its primary AP is lost.

Table G.2 High Rise Proof of Concept Meter Read Results

Group	AMI Read Success 4/1 to 4/15
High Rise	99.9%
Total AMI population	99.2%

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Appendix H: AMI System Requirements and Specifications

H.1 Meters

- 30-minute usage recording and storage for all customer segments
- Bi-directional (net) metering to support customers with energy sources such as solar, wind and future plug-in hybrid electric vehicles
- A service switch (internal disconnect switch) for every single-phase meter at 200 amps or less
- Basic power quality measurement (e.g., min/max/avg. voltage per interval)
- Meter events (e.g., tamper, meter health, power status, etc.)
- Capability of meters to poll and provide near-real-time data on consumption and other meter statuses

H.2 Network

- Two-way transmission of data with priority based messaging
- Remote reconfiguration of all programmable components of the AMI meters and network; specifically, this will include the meter firmware, the AMI communications firmware, and all home area communication firmware components, the AMI network concentrators, and other devices communicating on the AMI network
- Support for automatic meter reading of gas and water meters
- Available electricity consumption data from the network will be available for use on a daily or more frequent basis (i.e., all meters will be read minimally on a daily basis)

H.3 Back Office

- Web presentation of interval usage data daily to all customers
- Automated smart meter data feeds to new and existing systems (e.g., billing, meter data management, meter asset system)

H.4 AMI Technology Selection Criteria

In addition to the solution specifications above, ComEd worked with stakeholders to develop the AMI technology selection criteria. Through a separate, parallel process to the workshops, ComEd conducted a Request for Proposal (RFP) to select an AMI technology vendor. Stakeholders were involved during each step starting with the review of the RFP document and ending with the final review of the technical scoring for all of the RFP respondents. ComEd utilized ten (10) criteria, of which seven (7) were technical in nature. These seven technical evaluation criteria and corresponding weightings are reproduced in Table 6.1. These were used by ComEd in its RFP process resulting in the selection of the Pilot AMI technology and meter provider.

Table H.1 Technical Evaluation Criteria

Criteria	Description	Ranking
Security	Security for the grid as well as consumer protections	10
Network Performance	Flexibility in terms of networking technology. The solution will have to able to accommodate a number of potential program designs including innovative pricing programs, home area networking, distribution automation, plug-in electric vehicles, etc. This may be quantified in bandwidth margin and application prioritization capability.	9
Obsolescence Risk	Evaluation of technologies to ensure a solution with appropriate long-term value.	8
Flexibility & Scalability	Ability to adapt to smaller deployment increments, deployment to different service area or types, and deployment in more than one operating center (i.e., bids will be evaluated based on how easily the proposed solution scales for deployment throughout ComEd's entire service area).	7
Interoperability	Preference for nonproprietary solutions over proprietary solutions.	6
Capability	Ability to meet ComEd's operational goals in meter reading, meter servicing, theft detection, and outage management.	5
Maturity	Proven, demonstrated capabilities elsewhere	4

Appendix I: ISSGC Defined AMI Costs and Potential Benefits

Core AMI Functionality (ISSGC Report Pages 57-61)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Core AMI Functionality - Costs					
Cost	AMI Meters	N/A	N/A	Yes	Included in cost/benefit model. Based on Pilot experience for price, and for preferred specifications.
Cost	AMI Network	N/A	N/A	Yes	Included in cost/benefit model. Deployment quantities informed by Pilot experience. Pricing from Pilot extended, and updated by vendor.
Cost	AMI Management System	N/A	N/A	Yes	Included in cost/benefit model. Pilot business structure of outsourcing this operations extended and applied for business case. Pricing for full scale updated by vendor.
Cost	Meter Data Management System	N/A	N/A	Yes	Included in cost/benefit model. Pilot experience in integrating to billing and handling interval requirements has led to specification and requirement updates, and revisions to full scale pricing.
Cost	Early Retirement of Existing Meters	N/A	N/A	Yes	Evaluation identifies this as key policy issue that adjusts the financial results of business case. ComEd provided analysis of impact is included in Evaluation report. Not included in financial model.
Core AMI Functionality - Potential Benefits					
Potential Benefit	Increased field labor productivity	Primary	Utility	Yes	Detailed work levels based on Pilot experience, and associated department avoided costs and new costs are included in model and monetized for Meter Reading, Field Meter Services, Billing, Call Center, Revenue Mgmt, Revenue Protection, IT, PMO and AMO.
Potential Benefit	Employee safety	Primary	Utility	Yes	Not addressed explicitly in cost/benefit model. Department cost changes reflect decrease in ComEd injury and accident expenses. Vehicular miles of travel (VMT) estimated.
Potential Benefit	Improved forecasting of energy use	Primary	Utility	No	B&V recognize the potential benefit of ComEd having improved forecasting of energy use with the availability of internal meter read data for all its customers. Moreso, ComEd is able to understand both the load as well as load shape for the variety of customer segments. Specific to growth, ComEd can forecast energy usage patterns based on growth of individual customers segments as opposed to simply the aggregate.
Potential Benefit	Reduced back office support costs	Secondary	Utility	Yes	Detailed work levels based on Pilot experience, and associated department avoided costs and new costs are included in model and monetized for Meter Reading, Field Meter Services, Billing, Call Center, Revenue Mgmt, Revenue Protection, IT, PMO and AMO.
Potential Benefit	Reduced lost revenues (theft)	Secondary	Utility	Yes	Revenue impacts to UFE (theft, tamper) included in cost/benefit model and monetized; Pilot experience has informed ComEd of practicalities and business process design considerations around how to effectively identify tampered meters
Potential Benefit	Improved situational awareness	Secondary	Utility	Yes	Included in cost/benefit model as it relates to Outage Management. Model includes first stage levels of integration to OMS. Additional capabilities planned over time (but not included in cost/benefit model at this time).
Potential Benefit	Improved / expanded products and services (new rate programs)	Secondary	Competitive Supplier / Third-Party	N/A	ComEd is separately evaluating demand response opportunities. There are certain costs included in the cost/benefit model that may help facilitate demand response. These costs include customer education and outreach during deployment of the AMI system
Potential Benefit	Reduced carbon dioxide emissions. (ISSGCC states "minor" and related to reduced use of vehicles.)	Secondary	Society	Yes	The Evaluation estimates reductions due to VMT reduction and reduction in total GWhrs. These impacts are small on dollar terms assuming current carbon prices. The cost/benefit model does not include potential value of CO2 reductions.
Potential Benefit	Improved broadband communication network	Secondary	Society	N/A	This is not a benefit for ComEd. The AMI system assumes the use of public backhaul WAN services, not a propriatary communication backbone.

Core AMI Functionality (ISSGC Report Pages 58-61)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Core AMI Functionality - Negative Impacts					
Negative Impact	Implementation of pricing programs	N/A	N/A	No	ComEd's demand response initiative is out of scope of this evaluation.
Negative Impact	Costs of accelerated meter write down	N/A	N/A	Yes	Evaluation identifies this as key policy issue that adjusts the financial results of business case. ComEd provided analysis of impact is included in Evaluation report. Not included in financial model.
Negative Impact	Customer data privacy, data access by 3rd parties	N/A	N/A	No	The Evaluation has no adjustments to costs or benefits to account for requirements or impacts in this area. The Evaluation defers this as a policy issue for future ComEd consideration with its stakeholders.
Negative Impact	Meter readers today note hazards	N/A	N/A	Yes	The Evaluation includes cost estimates for AMI Meter inspection activities which will, in part, address this impact.

Remote Connect / Disconnect (Pages 62-64)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Remote Connect/Disconnect - Costs					
Cost	Integrated service switch	N/A	N/A	Yes	The cost of the disconnect / reconnect switch is included in meter price. The costs of system requirements is included in cost/benefit model. The costs of business process redesign and implementation of new business practices are included in cost/benefit model. Pilot experience has helped ComEd in preliminary assessment of business process requirements, including IT requirements.
Cost	New security requirements	N/A	N/A	Yes	B&V cost/benefit model assumptions assume that the ComEd specified vendor solutions meet all necessary system cybersecurity requirements. No separate costs have been considered.
Remote Connect/Disconnect - Potential Benefits					
Potential Benefit	Increased field labor productivity	Primary	Utility	Yes	Detailed work levels based on Pilot experience, and associated department avoided costs and new costs are included in model and monetized for Meter Reading, Field Meter Services, Billing, Call Center, Revenue Mgmt, Revenue Protection, IT, PMO and AMO.
Potential Benefit	Employee safety	Primary	Utility	Yes	Not addressed explicitly in cost/benefit model. Department cost changes reflect decrease in ComEd injury and accident expenses. Vehicular miles of travel (VMT) estimated. Fewer customer interface requirements during disconnect process.
Potential Benefit	Improved collections and cash flow	Primary	Utility	Yes	ComEd does not estimate any signficant improvement to the "meter-to-cash" revenue cycle. However, the cost/benefit model does include the reduction of bad debt expenses, due to new business practices associated with bad debt levels.
Potential Benefit	Reduced unbilled revenue	Secondary	Utility	Yes	The cost/benefit model includes detailed consideration for the reduction in unbilled revenue.
Potential Benefit	Reduced carbon dioxide emissions. (ISSGCC states "minor" and related to reduced use of vehicles.)	Secondary	Society	Yes	The Evaluation estimates reductions due to VMT reduction and reduction in total GWhrs. These impacts are small on dollar terms assuming current carbon prices. The cost/benefit model does not include potential value of CO2 reductions.
Potential Benefit	Enhanced services to customers	Secondary	Customer	Yes	The cost/benefit model does not include any monetization of this general benefit area. The report notes important OMS-related benefits that improve ability to troubleshoot outage conditions. Also, the Evaluation report estimates the "soft" demand response benefit associated with customers responding to the Pilot smart meter deployment and who visited the O Power website.

Remote Connect / Disconnect (Pages 62-64)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Remote Connect/Disconnect - Negative Impacts					
Negative Impact	Use of switch for non payment	N/A	N/A	Yes	Except for potential "door knock" cost sensitivity related to disconnection orders, the Evaluation has not included in the cost / benefit model and offsetting costs associated with compliance with any speculative requirements in these areas. The Evaluation report excludes consideration of the public policy dimensions of these considerations, and defers them for ComEd's consideration with its stakeholders.
Negative Impact	Customer safety and health impacts	N/A	N/A	No	
Negative Impact	Increased public safety costs	N/A	N/A	No	
Negative Impact	Less favorable customer agreements	N/A	N/A	No	
Negative Impact	Erroneous or unauthorized disconnections	N/A	N/A	No	

Power Quality/Voltage Monitoring at the Meter (Pages 68-70)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Power Quality/Voltage Monitoring at the Meter - Costs					
Cost	Additional measurement capabilities of the meter	N/A	N/A	Partially	The cost/benefit model includes meter price assumptions that reflect sophisticated power quality measurement capabilities of AMI meter design. ComEd anticipates using these capabilities over time. The cost/benefit model excludes consideration of any benefits in this area. This is deferred as a potential future benefit opportunity.
Cost	Modifications to back office systems to store and use the data	N/A	N/A	Partially	
Power Quality/Voltage Monitoring at the Meter - Potential Benefits					
Potential Benefit	Improved system reliability	Secondary	Utility	No	The Evaluation report excludes consideration and discussion of this policy area. Deferred for ComEd consideration with its stakeholders.
Potential Benefit	Improved system reliability	Secondary	Customer	No	
Potential Benefit	Improved power quality	Secondary	Customer	No	

Outage Management Support (Pages 65-67)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Outage Management Support - Costs					
Cost	Updating the outage management system	N/A	N/A	Yes	Costs included in the cost / benefit model.
Cost	Potential network design decisions required to increase the reliability of communications during outages.	N/A	N/A	Yes	ComEd estimates, and the cost / benefit model includes, sufficient network density to support intended levels of outage reporting. B&V has not independently verified network performance requirements, or potential incremental requirements associated with this requirement.
Outage Management Support - Potential Benefits					
Potential Benefit	Increased field labor productivity	Primary	Utility	Yes	Detailed work levels based on Pilot experience, and associated department avoided costs and new costs are included in model and monetized including those of distribution operations around storm and single-lights out events.
Potential Benefit	Improved system reliability	Primary	Utility	No	The Evaluation does not include an analysis of benefits related to system reliability.
Potential Benefit	Improved employee safety	Primary	Utility	Yes	Not addressed explicitly in cost/benefit model. Department cost changes reflect decreases in ComEd injury and accident expenses.
Potential Benefit	Improved situational awareness	Primary	Utility	Yes	The OMS-related benefits are included in the cost/benefit model. Situational awareness improves and drives specific OMS-related work levels and cost savings. Additional OMS benefit opportunities beyond those included are noted.
Potential Benefit	Reduced backoffice support costs	Secondary	Utility	Yes	In the area of outage mgmt, the evaluation considered benefits acheived by reduced truck rolls as well as backoffice support. Incremental OMS integration support costs are included in the model, as are AMO (operational) overheads in general to support operations.
Potential Benefit	Improved / expanded products and services	Secondary	Competitive Supplier / Third-Party	Yes	While not included in the quantified business case, potential future opportunities within the Outage Management area were assessed, considered, and documented accordingly.
Potential Benefit	Reduced carbon dioxide emissions. (ISSGCC states "minor" and related to reduced use of vehicles.)	Secondary	Society	Yes	The Evaluation estimates reductions due to VMT reduction and reduction in total GWhrs. These impacts are small on dollar terms assuming current carbon prices. The cost/benefit model does not include potential value of CO2 reductions.
Potential Benefit	Improved public health and safety	Secondary	Society	No	The Evaluation report excludes consideration and discussion of this policy area. Deferred for ComEd consideration with its stakeholders.
Potential Benefit	Improved economic productivity	Secondary	Society	No	The Evaluation report excludes consideration and discussion of this policy area. Deferred for ComEd consideration with its stakeholders.
Potential Benefit	Improved system reliability	Primary	Customer	No	The Evaluation report excludes consideration and discussion of this policy area. Deferred for ComEd consideration with its stakeholders.
Potential Benefit	Enhanced services to customers	Secondary	Customer	Yes	The Evaluation report excludes consideration and discussion of this policy area. Deferred for ComEd consideration with its stakeholders.

Customer Prepayment Utilizing AMI (Pages 71-73)

Type (Cost / Benefit / Negative Impact)	Potential Benefit and Beneficiary	Benefit (Primary / Secondary)	Benefit Beneficiary	Included in BV Evaluation?	Handling within B&V Evaluation, if applicable
Customer Prepayment Utilizing AMI - Costs					
Cost	Generally requires an in-premises display device for the customer to view remaining balance or other prepayment related information	N/A	N/A	No	These Application areas are out of scope of the ComEd business case. The Evaluation report does not include benefits in these areas.
Cost	Modification to billing system in order to support a prepayment program	N/A	N/A	No	
Cost	Modification to payment processing system for payment and application of payments	N/A	N/A	No	
Customer Prepayment Utilizing AMI - Potential Benefits					
Potential Benefit	improved collections and cash flow	Primary	Utility	No	These Application areas are out of scope of the ComEd business case. The Evaluation report does not include benefits in these areas.
Potential Benefit	improved / expanded products and services	Secondary	Competitive Supplier / Third-Party	No	
Potential Benefit	improved / expanded products and services	Primary	Customer	No	
Potential Benefit	reduced energy useage (conservation)	Secondary	Customer	No	
Customer Prepayment Utilizing AMI - Negative Impact					
Negative Impact	equity amongst customer classes	N/A	N/A	No	These Application areas are out of scope of the ComEd business case. The Evaluation report does not include benefits in these areas.
Negative Impact	predatory marketing	N/A	N/A	No	
Negative Impact	public safety and health	N/A	N/A	No	