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Via Electronic Filing

May 18, 2011

Terry J. Romine, Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 Saint Paul Street
Baltimore, Maryland 21202-6806

Re: Case No. 9208: In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost

Case No. 9207: In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure

Advanced Metering Infrastructure Performance Metrics Reporting Plan

Dear Ms. Romine:

Pursuant to Order Nos. 83531 and 83571 in Case Nos. 9208 and 9207 respectively, Baltimore Gas and Electric Company (BGE) and Potomac Electric Power Company (Pepco) submit this Advanced Metering Infrastructure (AMI) Performance Metrics Reporting Plan on behalf of the Working Group established by the Commission in those Orders. Ordering Paragraph 5 in Order Nos. 83531 and 83571 directed BGE and Pepco and the stakeholders in these cases to develop and submit for approval a comprehensive set of metrics to allow the Commission to assess the progress and performance of the two companies' Smart Grid Initiatives.

The Working Group met seven times from October 2010 to April 2011. The Working Group meetings were actively attended by the Staff of the Public Service Commission, BGE, Pepco, the Office of People's Counsel, the Maryland Energy Administration, Montgomery County Office of Consumer Protection, and AARP. After much discussion and input from the stakeholders, the Working Group was able to reach consensus on a comprehensive set of metrics that are designed to collect data on a range of

factors associated with Smart Grid deployment. As described in more detail in the Plan appended hereto, these metrics are divided into four categories: costs, project execution and delivery, operational benefits, and consumer education. Because some metrics will be evident and measurable in the near-term, and some will not manifest themselves until future programs are developed in more detail and deployment is well underway, these metrics will be assessed in two phases. Phase I metrics are designed to capture data during AMI deployment. These metrics relate to items such as costs, project delivery and installation, and initial impacts on utility operations and related activities that occur during the deployment phase. Phase II metrics will seek to measure the realization of benefits associated with implementation of AMI functionalities once enabled, for example, outage management and customer programs such as Smart Energy Pricing. The instant filing is comprised of Phase I metrics. The Plan provides an introduction to the Phase II metrics that will be considered by the Working Group; however, the process for identification and development of the Phase II metrics by the Working Group will not begin until the late second quarter/early third quarter of 2011. The Phase II metrics will be filed with the Commission prior to the implementation of the post-deployment programs.

Due to differing business case assumptions and deployment schedules, certain metrics will not be applicable to both utilities and certain metrics will be applicable during differing time periods for the utilities. These differences are discussed in more detail in the attached Advanced Metering Infrastructure Performance Metrics Reporting Plan, and identified in the metrics spreadsheet appended as Attachment 1 to the Plan. The spreadsheet provided in Attachment 1 to the Plan contains a detailed listing of the AMI Phase I Metrics including: definitions, calculations, data source, initial reporting period, and frequency of reporting for each Phase I Metric.

The Communication and Education Metrics reflected in these documents are identical to those included in Pepco's Consumer Education Plan and approved by the Commission by letter on February 18, 2011. BGE has agreed to incorporate those same metrics in its forthcoming Consumer Education Plan.

Cyber Security and Data Privacy are both of extremely high priority to the Utilities and the Working Group as a whole. Separate meetings will be held to continue our discussions around Cyber Security and Data Privacy. The issues surrounding Data Privacy and Cyber Security are not addressed herein and will be addressed separately from this filing.

Finally, Ordering Paragraph 5 of the two Orders directed BGE and Pepco and the stakeholders to develop a format for reporting these metrics to the Commission on a periodic schedule. Attachment 2 to the Plan contains the format agreed upon by the Working Group to report performance metrics to the Commission. The format is set up to identify a particular metric, together with a target, or projection representing the utilities' expectation for that particular metric, and the actual result. For example, the report contains a line item identifying the estimated cost to deploy the Smart Grid project for the

reporting quarter, along with the actual cost expended during that quarter. This reporting format complies with the Commission's Orders in that it will permit the Commission to assess the progress and performance of the Smart Grid Initiatives.

The Working Group respectfully requests Commission approval for these consensus documents.

Respectfully submitted,

/s/ Kimberly A. Curry

Kimberly A. Curry

KAC:jdb

Attachments

Advanced Metering Infrastructure Performance Metrics Reporting Plan
Phase I

Submitted by:

Potomac Electric Power Company
Baltimore Gas and Electric

I. Table of Contents

Acronyms

Acronym	Definition
Pepco	Potomac Electric Power Company
PHI	Pepco Holdings Inc.
BGE	Baltimore Gas & Electric
OPC	Maryland Office of People's Counsel
OCP	Montgomery County Office of Consumer Protection
DOE	The Department of Energy
RPM	Reliability Pricing Model
HTA	Hard to Access
AMI	Advanced Metering Infrastructure
MEA	Maryland Energy Administration
MD	Maryland
O&M	Operations and Maintenance

II. Executive Summary

A. Introduction

This document is Potomac Electric Power Company's (Pepco) and Baltimore Gas and Electric's (BGE) (herein referred to as "the Utilities," except where differentiation is required) response to Commission Order Nos. 83571 and 83531, dated September 2, 2010 and August 13, 2010 in Case Nos. 9207 and 9208, respectively. In these, the Public Service Commission of Maryland (herein referred to as "the Commission") granted the Utilities' request to proceed with the deployment of their respective Advanced Metering Infrastructure (AMI) in the state of Maryland.[1] As quoted in Order # 83571: "We also will require the Companies to develop – in consultation with the other parties to this Case – and to submit for Commission approval: (1) a detailed and comprehensive customer education and communications plan, which shall comply with the specifications provided in this Order, and which we expect the Companies to launch sufficiently in advance of AMI deployment in Maryland to optimize customer awareness and engagement; (2) a corresponding customer education and (3) a comprehensive set of metrics for all aspects of the Proposal, including but not limited to: (a) installation and performance of the technology; (b) incremental costs incurred; (c) incremental benefits realized; (d) effectiveness of customer education and communications efforts, to include, among other things, customer satisfaction and participation levels; and (e) customer privacy and cyber security. We will require the Companies to report to us their respective performance against these metrics, and to appear for periodic review hearings in which we will monitor each Company's progress toward achieving the goals set forth in their Proposal."

As a condition of the Commission's approval, the Utilities were ordered to convene and participate in a Smart Grid Implementation Working Group (herein referred to as "the Working Group")

[1] Order Nos. 83571 and 83531, paragraph 1.

to comply with modifications and parameters set forth by the Commission. The Working Group is led by Commission staff. The parties include representatives of the Maryland Office of People's Counsel (OPC), Maryland Energy Administration (MEA), Montgomery County Office of Consumer Protection (OCP), AARP, Pepco and BGE. The objectives[2] of the Working Group are to: (1) establish Consensus Education Plans and effectiveness metrics and reporting format for BGE and Pepco required in paragraph 4 of Order #83531 (BGE) and Order #83571 (Pepco); (2) establish consensus installation, performance, benefits, privacy, cyber security and budgetary metrics and reporting format for BGE and Pepco required in paragraph 5 of Order # 83531 and Order #83571; and (3) establish consensus recommendations for dynamic pricing implementation for BGE and Pepco in paragraph 10 of Order #83531 and Order #83571.

This document addresses objective (2). This document also includes the consumer education performance and effectiveness metrics that were included in the proposed Phase I Deployment and Installation Plan submitted by Pepco on January 31, 2011 and which was approved by the Commission in a letter dated February 18, 2011.[3] Specifically, this document includes:

- Phase I Deployment Phase installation, performance, budgetary and benefits metrics
- Identifies the general categories of Phase II Post Deployment/Implementation of Benefit Program performance, budgetary, and benefits metrics. The Working Group will begin the process of developing the Phase II metrics in Q2 of 2011.
- A Reporting Format for the proposed Phase I metrics

[2] Office of Staff Counsel - Smart Grid Implementation Working Group Status Report. Case Nos. 9207 and 9208, filed December 15, 2010.

[3] In addition, BGE's Education Plan will include four additional Communication and Education Metrics that are applicable to its implementation of the online energy manager web portal scheduled for implementation during the deployment phase of its AMI system in the spring of 2012. The metrics will be subject to revisions during the Working Group's compilation of the Phase II PSC metrics.

It is important to note that the metrics and benefits discussed in this document are subject to change as the AMI program progresses. The Pepco meter deployment of AMI is slated to begin in the second quarter of 2011. BGE's meter deployment is slated to begin the fourth quarter of 2011. Project investments, schedules, milestones, and costs could vary from current expectations. Both Utilities will continue to work with the Working Group to periodically review the relevance, value and effectiveness of the proposed metrics. Any proposed changes to these metrics will be submitted to the Commission for its review and approval.

Cyber Security and Data Privacy are both of extremely high priority to the Utilities and the Working Group as a whole. Separate meetings will be held to continue our discussions around Cyber Security and Data Privacy. The issues surrounding Data Privacy and Cyber Security are not addressed herein and will be addressed separately from this filing.

B. Guide to This Document

This document is comprised of four sections: the Table of Contents, the Executive Summary, Phase I metrics, and Phase II metrics. A brief description is provided below to help orient the reader:

- Table of Contents – Provides an outline of all major topics and sub-topics discussed in the document.
- Executive Summary – Provides context of the overall document including reference to the original Commission order, overall purpose of AMI metrics, and high-level reporting guidelines.
- Phase I metrics – Provides detailed discussion of Phase I metrics, the data sources that will be used to provide the results, and supporting background information for the recommended measures.

- Phase II metrics – Provides an overview of the categories of Phase II metrics. Specific Phase II metrics will be developed by the Utilities and submitted to the Working Group for review beginning in Q2 of 2011.

C. Purpose and Use of the Metrics

The Working Group established consensus around a set of critical metrics for Phase I, which is appended hereto as Attachment 1. To reach consensus, the Working Group met seven times between October of 2010 and April of 2011. These consensus metrics are expected to facilitate the monitoring, management and reporting of the AMI deployments. The metrics will also help drive results within a framework that systematically enforces accountability throughout all levels of the AMI programs.

The reporting of performance metrics and the tracking of costs and projected benefits serve two main purposes. The first purpose is to give the Utilities the ability to track their own progress and make adjustments as necessary to achieve goals and objectives that have been laid out in internal project plans and previous filings with the Commission. The Utilities and the Commission will use the feedback from the metrics to monitor progress and results of their respective AMI programs. The second purpose of the metrics and benefits reporting is to keep the Commission and Maryland stakeholders informed of the progress and impact of the AMI programs at both Utilities.

The Utilities will report metrics and benefits to the Commission quarterly (although some data is more appropriately reported annually). Pepco will submit its first quarterly report by Q4 2011, reflecting activities that occurred the previous quarter. BGE will submit its first quarterly report by Q1 2012, reflecting activities that occurred the previous quarter. This will allow the Commission and other stakeholders to understand, evaluate and ensure progress is being made on the AMI initiatives in a timely manner.

D. Guidelines for Reporting

The Utilities will report metrics separately to the Commission at regular intervals (more clearly defined in sections below). The Utilities have provided a sample report to be submitted for the Deployment Phase of the metrics (see Attachment 2). The report provides data on a per quarterly or annual basis. For each section, there is a "Target" column and a "Result" column. In the event that either the quarterly or the project-to-date results differ significantly from the targets, the Utilities will provide a rationale for the variance in the "Comments" column. The Utilities will report Phase I metrics through the deployment portion of their AMI projects. Once they are developed, the Phase II metrics will be reported through the completion of the overall AMI programs. Relevant Phase I metrics will continue to be reported during Phase II.

The Utilities have differing timetables for the implementation of Phase I and Phase II as defined in this document. Phase I consists primarily of the meter deployment itself. Pepco's meter deployment will take place from June 2011 through August 2012. BGE will deploy meters from October 2011 through June 2014. This Phase I Performance Metrics Report addresses the deployment phase of the AMI system and the initial impacts on utility operations and related impacts that can be reasonably quantified and reported during the initial stages of AMI deployment. The Phase II Performance Metrics Reporting Plan will reflect the implementation of new customer programs and AMI-related features and functions as identified in Section IV. Phases I and II may overlap in time to some extent, as utilities plan to begin some Phase II activities before the completion of Phase I deployment. The table shows the expected start and end dates for Phase I and Phase II for each utility:

	Phase I		Phase II	
	Start	End	Start	End
Pepco	June-2011	August-2012	July-2011	TBD
BGE	October-2011	June-2014	March-2012	TBD

Reports will be submitted on the 15th day of the 2nd month of the quarter following the reporting period, or the business day following the 15th day of the 2nd month of the quarter following the reporting period. For example, BGE's first reporting period will be Q4 2011. This report will be delivered by February 15, 2012.

III. Phase I Metrics

A. Summary

The Working Group has categorized the Advanced Metering Infrastructure metrics into Phase I (Deployment Phase) and Phase II (Realization of Post Deployment AMI Benefits) metrics. This section will provide details around the Phase I metrics. Phase I metrics include metrics associated with costs, project delivery and installation, and initial impacts on utility operations and related activities that occur during the deployment phase. Each metric will be reported quarterly or annually as described in Attachment 1. Two factors drove the decision of quarterly vs. annually reporting for each metric: one, an effort to be consistent with reporting of similar metrics internally and to other government entities, and two, a desire to provide meaningful data at meaningful intervals. The deployment schedule of the Utilities drives the availability of the data to generate the reports. Pepco is beginning meter deployment in Q2 2011, with significant activity starting in Q3 2011, and BGE starts AMI deployment in Q4 2011. Therefore, Pepco will submit its first quarterly report in Q4 2011 (Q3 2011 reporting period) and BGE will submit its first quarterly report in Q1 2012 (Q4 reporting period). As stated above, reports will be submitted on the 15th day of the 2nd month of the quarter, or the business day following the 15th day of the 2nd month of the quarter.

B. Objectives of the AMI Program and Corresponding Metrics

Phase I metrics can be aligned with the four overall objectives of the initial deployment of AMI meters:

- Initiation of customer education
- Installation and activation of the advanced metering and communication infrastructure across the service territory on schedule and within budget
- Realization of initial operational benefits
- Reporting of the results of forward looking Reliability Pricing Model (RPM) auctions that will impact the future benefits of dynamic pricing

Objective or Benefit	Key Metric
Initiation of customer education	% awareness of AMI technology and benefits (survey measurement)
	% understanding of AMI technology and benefits (survey measurement)
	# of community outreach events conducted and number of attendees at events
	# of articles that appear in local media
	# of articles in internal newsletter
	# of Meter Installation Complaints/Claims
	# of missed installation appointments
	# of customer organizations contacted
	# of customer referrals to energy advisors
	# of customer communication methods deployed
Installation and activation of the advanced metering infrastructure across the service territory on schedule and within budget	Total AMI meters installed
	Total AMI gas modules installed (BGE only)
	Total communication network components installed (access points & relays)
	Cost to Deploy: Capital vs. total Capital deployment cost
	Cost to Deploy: O&M vs. total O&M deployment cost
Installation and activation of the advanced metering infrastructure	DOE grants to the AMI, Direct Load Control and Customer Information System programs

Objective or Benefit	Key Metric
across the service territory on schedule and within budget	Total number of "Hard to Access" (HTAs) premises
	Total AMI meters used for billing (activated)
	Percentage of accounts with AMI meters that have to be estimated
	Number of consecutive estimated billing cycles (30, 60, 90 days on the system)
	Percentage of meters that pass side-by-side/dual pan meter tests (BGE Only)
	3rd Party Accuracy Test Percentage
	AMI Meter Sample Internal Test Results
	Percentage of interval reads received
Realization of initial operational benefits	Avoided new capital investment in new installations of the older metering systems due to customer growth
	Avoided planned replacement and maintenance costs relating to the older metering system *(e.g., mechanical meters, ERT devices, etc.)*
	Reduction in manual meter reading costs
	Reduction in meter operations costs (e.g., field visits, meter maintenance, etc.) (*BGE only in Phase I)*
	Reduced Theft of Energy
	# of avoided truck rolls
	# of AMI related call center calls
Results from forward looking RPM auctions and calculations of potential future value	Capacity price mitigation: - BGE /Pepco all Customers
	Capacity price mitigation: - Other MD customers
	Wholesale Capacity Revenues

C. Phase I Metrics Details

The Working Group has identified short-term objectives for the AMI programs. Phase I, or "Deployment," metrics will track short-term objectives and resulting impacts during the deployment phase of the new metering and communication systems.

In Phase I, the metrics are categorized into four sections:

- Financial Cost/Benefit;
- Project Delivery and Execution;

- Operational;
- Communication and Education.

Each of these four sections of metrics is covered in more detail below, with brief descriptions of what the section intends to measure. In general, it is the intent that the reported information can be traced back or audited to the utility records. In addition, where the metrics reflect activity for both gas and electric metering systems, BGE will report the information separately as noted on the attached Spreadsheet.

Financial Cost/Benefit Metrics

The financial cost/benefit metrics are important because they will measure progress towards meeting business goals by tracking quantitative financial costs and impacts on utility operations. Costs will be reported separately in terms of capital and O&M expenses.

Project Delivery and Execution Metrics

The project delivery and execution metrics are valuable as an assessment of the timeliness and quality delivery of the planned deployment and installation of the new metering and communication systems.

Operational Metrics

The operational metrics are important because they evaluate the processes and systems deployed to support AMI and dynamic pricing and how these support business needs. They also track whether the systems and processes are being used as intended.

The communications and education metrics provide an important evaluation of the effectiveness of customer education programs and assess the degree of customer knowledge and support.

1. Financial Cost/Benefits Metrics

In Phase I, Financial Cost/Benefits metrics are related to the cost of deployment and initial impacts on utility operations. Metrics will be reported quarterly or annually as indicated in Attachment 1.

Phase I Financial Cost/Benefit metrics are broken into five metric categories:

- Project Costs
- Capital Savings (direct & avoided)
- O&M Savings (direct & avoided)
- Other Economic Benefits
- Reporting of Wholesale Market Capacity Market actions that will impact future Dynamic Pricing Benefits.

Attachment 1 provides details of the metrics to be reported including the definition, calculation, frequency and the date the data for each metric is available.

a) Project Costs

Project Costs refer to the total spend vs. budget to date for the AMI project as a whole. This will be reported as an absolute dollar amount as well as a percentage of the remaining budget. Project Costs will be reported in two categories: Capital and O&M dollars. Each utility will break out projects costs by categories that align with their internal financial and project management structures as described more fully below.

BGE Project Cost Categories: [4]

Project	Definition
Meter Data Management	The Meter Data Management System (MDM) will become the single repository for all meter data for residential and small commercial customers. MDM will receive, process, and store residential and small commercial gas and electric customer meter readings. It will validate, edit, and estimate the readings and send bill determinants to BGE's new Customer Care and Billing system for it to calculate and produce customer bills.
AMI Meter Install/Provision	The AMI Meter Install/Provision project lays the foundation for the deployment of over two million gas and electric residential and small commercial AMI meters and will prepare the organization, processes, personnel and IT systems, for high-volume meter exchanges and associated impacts. The Meter I/P release ends with the first AMI meter installed and provisioned in Oct 2011.
Network Deployment	The Network Deployment project lays the foundation for the deployment of approximately 1200 devices to create a 2-way communications network. This project includes the activities necessary to design, build, test and deploy the various components of the network to support an advanced meter infrastructure, including Access Points, Relays, a Head-End (HE) system, a backhaul network and the associated integrations and business processes required for installation and provisioning using BGE's legacy systems. This project ends with the installation of the first network device in May of 2011.

[4] Costs will be incurred and reported in all 12 projects during Phase I. Costs will not be incurred in the Event Processing and Large C&I projects until late 2013 and 2014, the end of Phase I.

Project	Definition
Field Installations	The Field Installation project begins where the Meter Install/Provision and Network Deployment projects end. This project will manage the installation of over two million gas and electric residential and small commercial meters between Oct 2011 and June 2014. Likewise, it will oversee the installation of approximately 1200 network devices starting in May 2011. With VSI Meter Services, contractor line crews and BGE line crews, BGE will establish the detailed deployment plan and schedule the meter and network installations to efficiently deploy the new infrastructure. The construction crews will install the equipment and BGE will perform quality-assurance inspections of the installations.
AMI Register Billing	The AMI Register Billing project focuses specifically on two sets of activities: those necessary to automatically install and provision AMI meters to BGE's new Customer Care & Billing (CC&B) system and those required to automatically provide AMI meter consumption data for billing purpose.
Smart Energy Manager (SEM)	The SEM project provides a web portal and other tools to allow customers to begin to experience the benefits of the smart grid soon after their new advanced meter is installed. The SEM release will occur in March of 2012.
Smart Energy Manager II (SEM II)	The SEM II project will expand the offerings of the customer web portal to include additional functionality that will encourage customers to better manage their peak demand and energy usage. New capabilities such as peak event reports, savings summaries, peak event notifications and integrations with bge.com will be included in this release.

Project	Definition
Interval Billing/SEP	With the AMI Infrastructure and Meter Data Management (MDM) System in place, the Smart Energy Pricing (SEP) project can be implemented. Smart Energy Pricing requires that energy usage data be collected in at least one-hour intervals in order to measure customers' responses to pricing signals. BGE will implement a Peak Time Rebate incentive program for residential customers as our initial strategy, but can add other opt-in rates in the future.
Event Processing	The Event Processing project includes the definition of scope and completion of design for the integration of AMI with BGE's Outage Management System including planned work and service order creation. The implementation of Event Processing will occur outside of the 3-year build period and is scheduled for completion in March of 2014.
Large C&I	The Large C&I project will capture the costs of deploying Large C&I AMI meters.
Communications	The Communications project will develop and execute a proactive, sustained communications and education program. The plan will be based on customer research and segmentation. BGE will communicate early and often with customers and regularly measure customer satisfaction and acceptance/understanding.
Project Support Costs	Project support costs that are incremental to current capital and operating expenses will be tracked separately. These costs include the Project Management Office comprised of Project Managers with direct responsibility for each work packaged defined in the Project Execution Plan. Tasks include definition of scope, design, issue and risk management, scope management and managing and controlling deployment and implementation.

PEPCO Project Cost Categories:

Project	Definition
Meters	AMI Smart Meters includes all of the costs associated with the installation of Smart Meters, including contract labor
Communications Network	AMI Communications Equipment costs are comprised of two components: Communications Meter to Pole and Distribution Line Work
IT	IT systems used for AMI deployment. The costs are comprised of three components: Meter Data Management System & Dynamic Pricing Automated Deployment Software for Pepco Customer Benefit System Integration Software & Dynamic Pricing interfaces
Customer Education	The costs associated with planning and implementing the proposed Customer Education Plan include all marketing materials, contract fees for surveys and internal resources and external resources (i.e., Public Relations firms)

b) Capital Savings (Direct & Avoided) Metrics

Capital Savings (direct and avoided) will capture the realization of AMI benefits due to avoiding the planned replacement of current equipment and technologies as well as not installing current technology in new investment and growth during the deployment period.

c) O&M Savings (Direct & Avoided)

O&M Savings (direct and avoided) refer to the impact of the AMI investment on utility operations and costs incurred under the current metering system. These impacts will track the results from the reduction of meter reading positions, operational process efficiencies, and support function

process efficiencies. This will be reported as an absolute dollar amount as well as a percentage of the remaining budget. Project Costs will be reported in two categories: Capital and O&M dollars per Generally Accepted Accounting Principles.

d) Other Economic Benefits

A few of our benefits are categorized as Other Economic Benefits. These include Reduced Theft of Energy (due to the ability to detect meter tampering remotely) and Department of Energy grant payments to Direct Load Control programs (which are recorded as a benefit in the EmPower MD surcharge).

2. Monetization of Dynamic Pricing Resources

These categories (items 6, 7 and 8 on the Spreadsheet) represent the monetization of Dynamic Pricing resources. The majority of Dynamic Pricing benefits will be reported in Phase II. However, the Utilities will report on activities undertaken during the Phase I period on the activity related to the results of the PJM auctions. This information will report on auction results and calculations of potential benefits that will be delivered in the future based on the auction results.

3. Project Delivery & Execution Metrics

The project delivery and execution category metrics are broken into four metric categories:

- Meter Deployment;
- Network Deployment;
- Hard to Access Meters; and
- Meter Billing.

Each is covered in more detail below, with specific individual metrics included in each of the four categories.

a) Meter Deployment

The Meter Deployment metric will measure how many meters have been deployed. It will be expressed as a total number and as a percentage of total meters planned for deployment.

b) Network Deployment

The Network Deployment metric will measure how many network components have been deployed. It will be expressed as a total number and as a percentage of total network components planned for deployment.

c) Hard to Access Meters

Hard to access meters will be the number of hard to access premises which the AMI vendor must return to the utility for resolution.

d) Meter Billing

The Meter Billing metric will measure how many new meters are used to bill customers. It will be expressed as a total number and as a percentage of total premises.

4. Operational Metrics

The operational metric category is broken into four metric categories:

- Billing Accuracy;
- Field Visits;

- Meter Accuracy; and
- Meter Reading Effectiveness.

Each of these categories, along with specific individual metrics, is covered in more detail below.

a) Billing Accuracy

Billing Accuracy metrics focus on two areas: the number of accounts with AMI meters that need to be estimated, and the number of billing cycles an account has been estimated.

b) Field Visits

The Field Visit metric will provide insight into how the rollout of AMI impacts the need to send crews out for field inspections.

c) Meter Accuracy

Meter Accuracy metrics will focus on three different test results: side-by-side/dual pan meter tests, 3rd party accuracy tests, and internal sample tests.

d) Meter Reading Effectiveness

The meter reading effectiveness metric will measure the ability to get information from the meter to the Meter Data Management System. This will be measured and reported prior to automating customer billing. It measures the number of interval meter reads received by the Meter Data Management system verses the number of reads expected.

5. Communications & Education Metrics

The communications and education metric category is broken into two metric categories:

- Awareness and Understanding; and
- Community Outreach.

These two categories are covered below.

a) Awareness and Understanding

The Utilities will measure the customer reaction to and understanding of the deployment of the AMI system and satisfaction with the installation process with surveys. These metrics are intended to measure the effectiveness of the execution of the Utilities' communications and customer education strategy. The survey questions will be developed in consultation with the AMI Working Group.

b) Community Outreach

The Community Outreach metrics will measure the Utilities' effort to reach out to the local community.

IV. Phase II Metrics

A. Summary

The Working Group has also identified potential longer-term benefits associated with the actual implementation of the new technology. The Phase II metrics will seek to measure the realization of benefits associated with implementation of new AMI functionalities, such as outage management, customer service, continued implementation of operational efficiencies relating to remote connection and disconnection of meters and meter reading, presentation of web-based information to customers, and dynamic pricing activities. In Phase II, the primary categories of performance metrics are listed in the table below.

B. Phase II Metrics

Phase II metrics will be further defined later in 2011. The preliminary list of metric categories presented below is broken into three of the same four sections of metrics presented with the Phase I metrics above. The fourth section – project delivery and execution - is not included with the Phase II metrics as the focus will be on tracking benefits once the project has already been fully delivered and executed. The three Phase II metric sections are:

- Financial Cost/Benefit;
- Operational; and
- Communication and Education.

A potential list of metric categories is listed below.

AMI Metrics Section	Performance Metric Category
Financial Cost/Benefits	O&M Savings (direct & avoided)
Financial Cost/Benefits	Capital Savings (direct & avoided)
Financial Cost/Benefits	Dynamic Pricing Benefits
Financial Cost/Benefits	Other Economic Benefits
Operational	Field Visits
Operational	Number of remote connects / disconnects
Operational	Billing Accuracy
Operational	Reliability
Communications & Education	Customer Engagement
Communications & Education	Customer Satisfaction
Communications & Education	Dynamic Pricing Engagement
Communications & Education	Inquiries

Attachment 1

#	Metric Section	Metric Category	Key Metric	Definition	Calculation - BGE	Calculation - Pepco	Data Source	BGE - Initial Reporting Period	PEPCO - Initial Reporting Period	PSC Frequency	Gas, Electric, or Combination	Phase
1	Financial Cost/Benefits	AMI Project Costs	Cost to Deploy: Capital vs. total Capital deployment cost	Total capital dollars spent on the AMI deployment program inception to date vs. total AMI program capital budget as a dollar amount and as a ratio by project.	(1) Total dollars charged to the AMI projects for capital expenses incurred in project (2) Total actual capital expenditures of all AMI projects to date divided by the sum of the total projects' budgeted capital expenditures expressed as a percentage. Costs will be categorized by the following projects: - Meter Data Management - AMI Meter Install/Provision - Network Deployment - Field Installations - AMI Register Billing - Smart Energy Manager (SEM) - Smart Energy Manager II (SEM II) - Interval Billing/SEP - Event Processing - Large C&I - Communications - Project Support Costs	(1) Total dollars charged to the AMI projects for capital expenses incurred in project (2) Total actual capital expenditures of all AMI projects to date divided by the sum of the total projects' budgeted capital expenditures expressed as a percentage. Costs will be categorized by the following projects: - Meters - Communications Network - IT - Customer Education	AMI project codes derived from financial system of record	Q4 2011	Q3 2011	Quarterly	Combination Note: Both gas and electric will be reported. Gas will be reported as separate line items	Deployment Phase
2	Financial Cost/Benefits	AMI Project Costs	Cost to Deploy: O&M vs. total O&M deployment cost	Total O&M dollars spent on the AMI deployment program inception to date vs. total AMI project O&M budget as a dollar amount and as a ratio by project.	(1) Total dollars charged to the AMI projects for O&M expenses incurred in project (2) Total actual O&M expenditures of all AMI projects to date divided by the sum of the total projects' budgeted capital expenditures expressed as a percentage. Costs will be categorized by the following projects: - Meter Data Management - AMI Meter Install/Provision - Network Deployment - Field Installations - AMI Register Billing - Smart Energy Manager (SEM) - Smart Energy Manager II (SEM II) - Interval Billing/SEP - Event Processing - Large C&I - Communications - Project Support Costs	(1) Total dollars charged to the AMI projects for O&M expenses incurred in project (2) Total actual O&M expenditures of all AMI projects to date divided by the sum of the total projects' budgeted capital expenditures expressed as a percentage. Costs will be categorized by the following projects: - Meters - Communications Network - IT - Customer Education	AMI project codes derived from financial system of record	Q4 2011	Q3 2011	Quarterly	Combination	Deployment Phase
3	Financial Cost/Benefits	Capital Savings (direct & avoided)	DOE Reimbursement - AMI only	Portion of Department of Energy Smart Grid Investment Grants received and applied to offset cost of AMI and ratio of total grant.	Eligible amount of AMI DOE expenses invoiced ($). Eligible amount of AMI DOE expenses invoiced/Total AMI DOE Grant.	Eligible amount of AMI DOE expenses invoiced ($). Eligible amount of AMI DOE expenses invoiced/Total AMI DOE Grant.	AMI project codes derived from financial system of record	Q1 2011	Q3 2011	Quarterly	Combination	
4	Financial Cost/Benefits	Capital Savings (direct & avoided)	Avoided new capital investment in new installations of the older metering systems due to customer growth	Total dollar value of avoided legacy metering capital costs for new customers and new developments.	(2008-2010 average cost to install meter(materials and labor)) * (Handy Whitman inflation factor) * (# of avoided legacy meters from new customer installations + # of avoided legacy meters from new development installations)	(2008-2010 average cost to install meter(materials and labor)) * (Handy Whitman inflation factor) * (# of avoided legacy meters from new customer installations + # of avoided legacy meters from new development installations)	Operations group and financial system of record	Q1 2012	Q1 2013	Quarterly	Combination	

#	Metric Section	Metric Category	Key Metric	Definition	Calculation - BGE	Calculation - Pepco	Data Source	BGE - Initial Reporting Period	PEPCO - Initial Reporting Period	PSC Frequency	Gas, Electric, or Combination	Phase
5	Financial Cost/Benefits	Capital Savings (direct & avoided)	Avoided planned replacement and maintenance costs relating to the older metering system *(e.g., mechanical meters, ERT devices, etc)*	Total dollar value of avoided replacement costs of current metering equipment	Avoided cost to upgrade AMR system (meter reading IT system) plus 2008-2010 average cost per ITRON unit replacement * Handy Whitman inflation factor * number of scheduled replacements plus 2008-2010 average cost per meter replacement (materials and labor) * Handy Whitman inflation factor * number of scheduled replacements	(2008 - 2010 average capital cost of electric non-AMI meters) minus (Like capital cost in current period)	Operations group and financial system of record	Q1 2012	Q1 2012	Annually	Combination	Deployment Phase
6	Financial Cost/Benefits	Monetizaiton of Dynamic Pricing Resources	Wholesale Capacity Auction Result dollars	Results from bidding dynamic pricing as a capacity resource in the RPM auctions (PJM capacity markets) (benefit realized during the delivery year)	cleared volume (MW) * final weighted cleared price for delivery year X	cleared volume (MW) * final weighted cleared price for delivery year X	PJM Market *(PJM Web Account)*	Q4 2011	Q4 2011	Annually	Electric	Deployment Phase
7	Financial Cost/Benefits	Monetizaiton of Dynamic Pricing Resources	Calculation of Capacity price mitigation based on wholesale capacity auctions results: - BGE /Pepco all customers	Expected benefit to all (BGE or Pepco) Zone Customers due to dynamic pricing capacity participation in RPM auctions (benefit realized during the delivery year)	Expected Benefit to all BGE customers = [Total BGE Zone capacity obligation (MW) * clearing price without bidding BGE dynamic pricing MWs ($ per MW-day)] - [Total BGE Zone capacity obligation (MW) * clearing price ($ per MW-day)] for delivery year X Note: exploring PJM running RPM price model after the auction to determine impact of capacity resources	Expected Benefit to all Pepco customers = [Total Pepco Zone capacity obligation (MW) * clearing price without bidding Pepco dynamic pricing MWs ($ per MW-day)] - [Total Pepco Zone capacity obligation (MW) * clearing price ($ per MW-day)] for delivery year X Note: exploring PJM running RPM price model after the auction to determine impact of capacity resources	PJM Market *(PJM planning parameters)*	Q4 2011	Q4 2011	Annually	Electric	Deployment Phase
8	Financial Cost/Benefits	Monetizaiton of Dynamic Pricing Resources	Calculation of Capacity price mitigation based on wholesale capacity auctions results: - Other MD customers	Expected benefit to other MD Customers in the SWMAAC and Eastern MACC regions due to dynamic pricing capacity participation in RPM auctions (benefit realized during the delivery year)	Expected Benefit to other MD customers (1) = [Total BGE MD capacity obligation (MW) * clearing price without bidding BGE dynamic pricing MWs ($ per MW-day)] - [Total BGE MD capacity obligation (MW) * clearing price ($ per MW-day)] for delivery year X (1) SWMAAC and Eastern MACC only includes the BGE Zone and the PEPCO (MD/DC) Zone Note: exploring PJM running RPM price model after the auction to determine impact of capacity resources	Expected Benefit to other MD customers (1) = [Total BGE MD capacity obligation (MW) * clearing price without bidding BGE dynamic pricing MWs ($ per MW-day)] - [Total BGE MD capacity obligation (MW) * clearing price ($ per MW-day)] for delivery year X (1) SWMAAC and Eastern MACC only includes the BGE Zone and the PEPCO (MD/DC) Zone Note: exploring PJM running RPM price model after the auction to determine impact of capacity resources	PJM Market *(PJM planning parameters)*	Q4 2011	Q4 2011	Annually	Electric	Deployment Phase
9	Financial Cost/Benefits	O&M Savings (direct & avoided)	Reduction in manual meter reading costs	Cost reductions due to the elimination of meter reading positions (in-house and contract)	(2008-2010 average number of meter readers - YTD average number of meter readers) * (YTD meter reader fully loaded labor costs / YTD average number of meter readers) **Plus** (2008-2010 average monthly contractor costs inflation-adjusted using the CPI to current * months to date) - (YTD contractor costs)	(2008-2010 average actual contract cost) (actual cost per meter read * the number of meters reads billed) (Note: The current contract is up for re-negotiation and billing parameters will change) **Plus:** (2008 - 2010 average cost of special contract meter reading) minus (Like costs for current period).	Operations group and financial system of record	Q2 2012	Q2 2012	Annually	Electric	Deployment Phase
10	Financial Cost/Benefits	O&M Savings (direct & avoided)	Reduction in meter operations costs (e.g., field visits, meter maintenance, etc) (*BGE only in Phase I)*	Meter operations savings due to lower survey meter activities and ERT battery replacement costs.	(2008-2010 average cost of electric & gas survey meter activities)-(Like cost in current period) **Plus** 2008-2010 average cost of ERT battery replacement (materials and labor) *Handy Whitman inflation factor * number of scheduled replacements	NA	Operations group and financial system of record	Q1 2012	NA	Annually	Combination	Deployment Phase

#	Metric Section	Metric Category	Key Metric	Definition	Calculation - BGE	Calculation - Pepco	Data Source	BGE - Initial Reporting Period	PEPCO - Initial Reporting Period	PSC Frequency	Gas, Electric, or Combination	Phase
11	Financial Cost/Benefits	Other Economic Benefits	Reduced Theft of Energy	The number of incidents of theft of energy uncovered and the dollar amount billed for theft of energy.	1) Number of theft incidents 2) Incremental Dollar amount billed for identified theft consumption	1) Number of theft incidents 2) Incremental Dollar amount billed for identified theft consumption	Customer information System	Q3 2013	Q1 2013	Annually	Combination	Deployment Phase
12	Financial Cost/Benefits	Other Economic Benefits	DOE grants to Direct Load Control and Customer Information System programs	Portion of Department of Energy Smart Grid Investment Grants invoiced and applied to offset the cost of Direct Load Control and Customer Information System projects *Note: Dollars currently appear as a reduction to the EM Power Maryland Surcharge.*	Eligible amount invoiced to DOE for expenses incurred in the BGE Direct Load Control and Customer Information System project	Eligible amount invoiced to DOE for expenses incurred in the Pepco Direct Load Control project	Reimbursement project code derived from financial system of record	Q4 2011	Q3 2011	Annually	Electric	Deployment Phase
13	Project Delivery & Execution	Meter Deployment	Total AMI electric meters installed	Total AMI electric meters installed (physically attached to a premise) expressed as total number and percent of total	1) Total number of actual AMI electric meters installed 2) Total number of actual AMI electric meters installed divided by the planned total number of meters	1) Total number of actual AMI electric meters installed 2) Total number of actual AMI electric meters installed divided by the planned total number of meters	Meter Monitoring System / Meter Data Management System	Q4 2011	Q3 2011	Quarterly	Electric	Deployment Phase
14	Project Delivery & Execution	Meter Deployment	Total AMI gas modules or gas meters Installed (BGE Only) .	Total AMI gas modules installed (physically attached to a premise) expressed as total number and percent of total	1) Total number of actual AMI gas modules installed 2) Total number of actual AMI gas modules installed divided by the planned total number of gas modules	NA	Meter Monitoring System / Meter Data Management System	Q4 2011	NA	Quarterly	Gas	Deployment Phase
15	Project Delivery & Execution	Network Deployment	Total communication network components installed (access points & relays)	Total communication network components installed (access points & relays) expressed as total number and percent of total	1) Total number of actual installed access points & relays (repeaters) 2) Total number of actual installed access points & relays and repeaters divided by the planned total number of access points & relays (repeaters) expressed as a percentage.	1) Total number of actual installed access points & relays (repeaters) 2) Total number of actual installed access points & relays and repeaters divided by the planned total number of access points & relays (repeaters) expressed as a percentage.	Meter Monitoring System / Meter Data Management System	Q4 2011	Q3 2011	Quarterly	Electric	Deployment Phase
16	Project Delivery & Execution	Hard to Access Meters	Total number of "Hard to Access" (HTAs) premises	# of hard to access premises which the AMI vendor must return to the utility for AMI meter installation.	# of HTAs where BGE has exhausted all its options to conduct an exchange and the last resort is possible disconnection.	# of HTAs where Pepco has exhausted all its options to conduct an exchange and the last resort is possible disconnection.	Meter Monitoring System / Meter Data Management System	Q4 2011	Q3 2011	Quarterly	Combination	Deployment Phase
17	Project Delivery & Execution	Meter Billing	Total AMI meters used for billing (activated), communications achieved and used to bill monthly	Total AMI meters used for billing (activated, i.e. communicating with meter to produce customer bill) expressed as total number and percent of total	1) Total number of actual active AMI meters 2) Total number of actual active AMI meters divided by the planned total number of active AMI meters	1) Total number of actual active AMI meters 2) Total number of actual active AMI meters divided by the planned total number of active AMI meters	Meter Monitoring System / Meter Data Management System	Q2 2012	Q2 2012	Quarterly	Combination	Deployment Phase
18	Operational	Billing Accuracy	Percentage of accounts with AMI meters that have to be estimated	Percentage of accounts with AMI meters where any portion of the bill has to be estimated	(AMI Meters Estimated for billing purposes /AMI Total Activated (used for billing))*100 *Note: The 2008-2010 average will be provided as a foot note for comparison purposes*	(AMI Meters Estimated for billing purposes /AMI Total Activated (used for billing))*100 *Note: The 2008-2010 average will be provided as a foot note for comparison purposes*	Customer information system	Q2 2012	Q2 2012	Quarterly	Combination	Deployment Phase
19	Operational	Billing Accuracy	Number of consecutive estimated billing cycles (30,60,90 days on the system)	A count of estimated bills and their respective durations before there is an actual reading that results in bill being generated for the customer.	# of estimated bills at 30, 60, and 90 days estimated # estimation bill accts in each aging bucket/ total number of bill accts *Note: The 2008-2010 average will be provided as a foot note for comparison purposes*	# of estimated bills at 30, 60, and 90 days estimated # estimation bill accts in each aging bucket/ total number of bill accts *Note: The 2008-2010 average will be provided as a foot note for comparison purposes*	Customer information system	Q2 2012	Q2 2012	Quarterly	Combination	Deployment Phase
20	Operational	Field Visits	# of avoided truck rolls	Number of avoided truck rolls for meter field inspections. *Note: Will include number of deployment truck rolls as a footnote*	((2008-2010 average # of truck rolls) * (truck roll growth factor))- (current # of truck rolls)	(2008-2010 average # of truck rolls) - (current # of truck rolls)	Work Management System	Q1 2013	Q2 2012	Quarterly	Combination	Deployment Phase
21	Operational	Meter Accuracy	Percentage of meters that pass side-by-side/dual pan meter tests (BGE Only)	Percentage of meters that pass side-by-side/dual pan meter tests (BGE Only) based on statistically significant sample size where AMI meters are installed next to legacy meters and compared manually.	Sample Size Population Based on 95% Confidence Level and a 5% Confidence Interval. Proposed Tolerance Level +/- 2% # of Dual Pans within tolerance divided by total number of dual pan installs.	NA	Meter Monitoring System / Meter Data Management System	Q4 2011	NA	Annually	Combination	Deployment Phase

#	Metric Section	Metric Category	Key Metric	Definition	Calculation - BGE	Calculation - Pepco	Data Source	BGE - Initial Reporting Period	PEPCO - Initial Reporting Period	PSC Frequency	Gas, Electric, or Combination	Phase
22	Operational	Meter Accuracy	3rd Party Accuracy Test Percentage	Percentage of meters that pass 3rd party accuracy test. A statistically significant sample of meters will be sent from the vendor to a third party to be tested prior to being tested internally	Report from vendor - plan now is to import those results into MTS - meter test system in the EMC test shop	Pepco will submit previously completed 3rd Party accuracy reports.	Vendor Provided Meter Test System	Q4 2011	Q4 2011	Quarterly	Electric	Deployment Phase
23	Operational	Meter Accuracy	AMI Meter Sample Internal Test Results	Percentage of AMI meters that pass internal accuracy testing prior to deployment	• A sample of meters (determined by ANSI Z1.4) will be tested prior to releasing a shipment into inventory for installation • Solid state electric meter accuracy of X% will be required	• A sample of meters (determined by ANSI Z1.4) will be tested prior to releasing a shipment into inventory for installation • Solid state electric meter accuracy of X% will be required	Meter Monitoring System / Meter Data Management System	Q4 2011	Q3 2011	Quarterly	Electric	Deployment Phase
24	Operational	Meter Reading Effectiveness	Percentage of interval reads received	# of intervals reported / total number of possible intervals to be reported	# of intervals reported / total number of possible intervals to be reported * 100	# of intervals reported / total number of possible intervals to be reported * 100	Meter Monitoring System / Meter Data Management System	Q4 2011	Q2 2012	Quarterly	TBD	Deployment Phase
25	Communications & Education	Awareness and Understanding	% awareness of AMI technology and benefits (survey measurement)	% awareness of customers based on survey results; target to be determined after baseline established (with and w/o internet access)	3rd Party Survey	3rd Party Survey	3rd Party Customer Survey	Q1 2012	Q3 2011	Quarterly	Combination	Deployment Phase
26	Communications & Education	Awareness and Understanding	% understanding of AMI technology and benefits (survey measurement)	% understanding of customers based on survey results; target to be determined after baseline established (with and w/o internet access)	3rd Party Survey	3rd Party Survey	3rd Party Customer Survey	Q1 2012	Q3 2011	Annually	Combination	Deployment Phase
27	Communications & Education	Community Outreach	# of community outreach events conducted and number of attendees at events	- Number of events held to educate customers on smart meter functionality - Number of customers attending educational events	Count of events and number of attendees	Count of events and number of attendees	Internal Tracking Spreadsheet	Q4 2011	Q3 2011	Annually	Combination	Deployment Phase
28	Communications & Education	Community Outreach	# of articles that appear in local media	Number of articles that appear in local media as a result of company issued press releases	Count of articles that appear in local media as a result of company issued press releases	Count of articles that appear in local media as a result of company issued press releases	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase
29	Communications & Education	Community Outreach	# of articles in internal newsletter	Number of articles in internal newsletter	Count of articles in internal newsletter	Count of articles in internal newsletter	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase
30	Communications & Education	Customer Satisfaction	# of Meter Installation Complaints/Claims	Number of Meter Installation complaints/claims	Count of Meter Installation complaints/claims	Count of Meter Installation complaints/claims	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase
31	Communications & Education	Customer Satisfaction	# of missed installation appointments	Number of missed appointments	Count of missed appointments	Count of missed appointments	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase
32	Communications & Education	Community Outreach	# of customer organizations contacted	Number of customer organization contacted	Count of customer organizations contacted	Count of customer organizations contacted	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase
33	Communications & Education	Customer Satisfaction	# of customer referrals to energy advisors	# of transfers to energy advisors for information on AMI deployments	Count of number of referrals	Count of number of referrals	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase
34	Communications & Education	Community Outreach	# of customer communication methods deployed	# of publications distributed or other communication vehicles deployed by type	Count of number of items	Count of number of items	Internal Tracking Spreadsheet	TBD	Q3 2011	Quarterly	Combination	Deployment Phase

Attachment 2

Advanced Metering Infrastructure Performance Metrics Report

Executive Summary:

- The following represents Baltimore Gas and Electric (BGE) Q4 2012 report on Smart Grid Initiative metrics to the Maryland Public Service Commission

#	Metric Category	Key Metric	Calculation	Results Q4 2012	Target Q4 2012	Results Project to Date	Target Project to Date	Comment
Financial Metrics								
1	AMI Project Costs	Cost to Deploy: Capital vs. total Capital deployment cost (Electric)	(1) Total dollars charged to the AMI projects for capital expenses incurred in project (2) Total actual capital expenditures of all AMI projects to date divided by the sum of the total projects' budgeted capital expenditures expressed as a percentage. Costs will be categorized by the following projects: - Meter Data Management - AMI Meter Install/Provision	$ 6,450,555	$ 6,665,000	$ 65,731,657	$ 64,500,000	NOTE: Each company would break these line items out by there repective projects. BGE would have 12 line items and Pepco 4. BGE would also have separate line items for gas.
		Cost to Deploy: Capital vs. total Capital deployment cost (Gas)	- Network Deployment - Field Installations - AMI Register Billing - Smart Energy Manager (SEM) - Smart Energy Manager II (SEM II) - Interval Billing/SEP - Event Processing - Large C&I - Communications - Project Support Costs	$ 1,050,090	$ 1,085,000	$ 10,700,502	$ 10,500,000	
2	AMI Project Costs	Cost to Deploy: O&M vs. total O&M deployment cost (Electric)	(1) Total dollars charged to the AMI projects for O&M expenses incurred in project (2) Total actual O&M expenditures of all AMI projects to date divided by the sum of the total projects' budgeted capital expenditures expressed as a percentage. Costs will be categorized by the following projects: - Meter Data Management - AMI Meter Install/Provision	$ 1,065,150	$ 1,075,000	$ 8,802,500	$ 8,600,000	
		Cost to Deploy: O&M vs. total O&M deployment cost (Gas)	- Network Deployment - Field Installations - AMI Register Billing - Smart Energy Manager (SEM) - Smart Energy Manager II (SEM II) - Interval Billing/SEP - Event Processing - Large C&I - Communications - Project Support Costs	$ 173,396	$ 175,000	$ 1,432,965	$ 1,400,000	
		Total Electric		*$ 7,515,704*	*$ 7,740,000*	*$ 74,534,157*	*$ 73,100,000*	
		Total Gas		*$ 1,223,487*	*$ 1,260,000*	*$ 12,133,467*	*$ 11,900,000*	
		Total Costs		**$ 8,565,795**	**$ 8,825,000**	**$ 85,234,659**	**$ 83,600,000**	

Advanced Metering Infrastructure Performance Metrics Report

#	Metric Category	Key Metric	Calculation	Results Q4 2012	Target Q4 2012	Results Project to Date	Target Project to Date	Comment
			Financial Metrics Continued					
3	Capital Savings (direct & avoided)	DOE Reimbursement - AMI only	Eligible amount of AMI DOE expenses invoiced ($). Eligible amount of AMI DOE expenses invoiced/Total AMI DOE Grant.	$ 3,250,000	$ 3,300,000	$ 28,250,648	$ 32,000,000	
		Net Costs		**$ 5,315,795**	**$ 5,525,000**	**$ 56,984,011**	**$ 51,600,000**	
4	Capital Savings (direct & avoided)	Avoided new capital investment in new installations of the older metering systems due to customer growth	(2008-2010 average cost to install meter(materials and labor)) * (Handy Whitman inflation factor) * (# of avoided legacy meters from new customer installations + # of avoided legacy meters from new development installations)	$ 30,094	$ 28,000	$ 142,866	$ 140,000	
5	Capital Savings (direct & avoided)	Avoided planned replacement and maintenance costs relating to the older metering system (e.g., mechanical meters, ERT devices, etc)	Avoided cost to upgrade AMR system (meter reading IT system) plus 2008-2010 average cost per ITRON unit replacement * Handy Whitman inflation factor * number of scheduled replacements plus 2008-2010 average cost per meter replacement (materials and labor) * Handy Whitman inflation factor * number of scheduled replacements	$ 75,235	$ 70,000	$ 357,165	$ 350,000	
6	Monetizaiton of Dynamic Pricing Resources	Wholesale Capacity Auction Result dollars	cleared volume (MW) * final weighted cleared price for delivery year X	$ 123,256	$ 100,000	$ 525,125	$ 500,000	
7	Monetizaiton of Dynamic Pricing Resources	Calculation of Capacity price mitigation based on wholesale capacity auctions results: - BGE /Pepco all customers	Expected Benefit to all BGE customers = [Total BGE Zone capacity obligation (MW) * clearing price without bidding BGE dynamic pricing MWs ($ per MW-day)] - [Total BGE Zone capacity obligation (MW) * clearing price ($ per MW-day)] for delivery year X Note: exploring PJM running RPM price model after the auction to determine impact of capacity resources	$ 9,000,000	$ 8,500,000	$ 9,000,000	$ 8,500,000	- Represents annual benefit for 2012

#	Metric Category	Key Metric	Calculation	Results Q4 2012	Target Q4 2012	Results Project to Date	Target Project to Date	Comment
Financial Metrics Continued								
8	Monetizaiton of Dynamic Pricing Resources	Calculation of Capacity price mitigation based on wholesale capacity auctions results: - Other MD customers	Expected Benefit to other MD customers (1) = [Total BGE MD capacity obligation (MW) * clearing price without bidding BGE dynamic pricing MWs ($ per MW-day)] - [Total BGE MD capacity obligation (MW) * clearing price ($ per MW-day)] for delivery year X (1) SWMAAC and Eastern MACC only includes the BGE Zone and the PEPCO (MD/DC) Zone Note: exploring PJM running RPM price model after the auction to determine impact of capacity resources	$ 29,000,000	$ 30,000,000	$ 29,000,000	$ 30,000,000	- Represents annual benefit for 2012
9	O&M Savings (direct & avoided)	Reduction in manual meter reading costs	(2008-2010 average number of meter readers - YTD average number of meter readers) * (YTD meter reader fully loaded labor costs / YTD average number of meter readers) Plus (2008-2010 average monthly contractor costs inflation-adjusted using the CPI to current * months to date) - (YTD contractor costs)	$ 13,000,000	$ 13,500,000	$ 13,000,000	$ 13,500,000	- Represents annual benefit for 2012
10	O&M Savings (direct & avoided)	Reduction in meter operations costs (e.g., field visits, meter maintenance, etc) (BGE only in Phase I)	(2008-2010 average cost of electric & gas survey meter activities)-(Like cost in current period) Plus 2008-2010 average cost of ERT battery replacement (materials and labor)	$ 356,125	$ 350,000	$ 1,894,562	$ 2,000,000	
11	Other Economic Benefits	Reduced Theft of Energy	1) Number of theft incidents 2) Incremental Dollar amount billed for identified theft consumption	$ 327,584	$ 320,000	$ 1,258,951	$ 1,250,000	
12	Other Economic Benefits	DOE grants to Direct Load Control and Customer Information System programs	Eligible amount invoiced to DOE for expenses incurred in the BGE Direct Load Control and Customer Information System project	$ 297,459	$ 300,000	$ 1,335,678	$ 1,250,000	
13	Meter Deployment	Total AMI electric meters installed	1) Total number of actual AMI electric meters installed 2) Total number of actual AMI electric meters installed divided by the planned total number of meters	$ 120,496	$ 120,000	$ 251,684	$ 250,000	
		Realized Benefits		$ 1,300,155	$ 1,260,000	$ 5,623,165	$ 5,600,000	
		Forward looking dynamic pricing benefits		$ 51,000,000	$ 52,000,000	$ 51,000,000	$ 52,000,000	

Financial Cost/Benefits Metrics Commentary

- BGE expects costs and benefits to continue in line with the budget

Advanced Metering Infrastructure Performance Metrics Report

#	Metric Category	Key Metric	Calculation	Results Q4 2012	Target Q4 2012	Results Project to Date	Target Project to Date	Comment
Project Delivery & Execution Metrics								
14	Meter Deployment	Total AMI gas modules or gas meters Installed (BGE Only) .	1) Total number of actual AMI gas modules installed 2) Total number of actual AMI gas modules installed divided by the planned total number of gas modules	84,000	82,000	504,000	500,000	
15	Network Deployment	Total communication network components installed (access points & relays)	1) Total number of actual installed access points & relays (repeaters) 2) Total number of actual installed access points & relays and repeaters divided by the planned total number of access points & relays (repeaters) expressed as a percentage.	49856	50000	300,125	300,000	
16	Hard to Access Meters	Total number of "Hard to Access" (HTAs) premises	# of HTAs where BGE has exhausted all its options to conduct an exchange and the last resort is possible disconnection.	144	150	960	980	
17	Meter Billing	Total AMI meters used for billing (activated), communications achieved and used to bill monthly	1) Total number of actual active AMI meters 2) Total number of actual active AMI meters divided by the planned total number of active AMI meters	325	300	2,845	2,500	
18	Billing Accuracy	Percentage of accounts with AMI meters that have to be estimated	(AMI Meters Estimated for billing purposes /AMI Total Activated (used for billing))*100 Note: The 2008-2010 average will be provided as a foot note for comparison purposes	44,870	75,000	270,113	450,000	

Project Delivery & Execution metrics commentary

- The Phase one Project Delivery & Execution metrics are inline with expectations

Advanced Metering Infrastructure Performance Metrics Report

#	Metric Category	Key Metric	Calculation	Results Q4 2012	Target Q4 2012	Results Project to Date	Target Project to Date	Comment
Operational Metrics								
19	Billing Accuracy	Number of consecutive estimated billing cycles (30,60,90 days on the system)	# of estimated bills at 30, 60, and 90 days estimated # estimation bill accts in each aging bucket/ total number of bill accts Note: The 2008-2010 average will be provided as a foot note for comparison purposes	7%	2%	42%		
20	Field Visits	# of avoided truck rolls	((2008-2010 average # of truck rolls) * (truck roll growth factor))- (current # of truck rolls)	30 - 24,563 60 - 8,952 90 - 2,654	30 - 20,000 60 - 6,000 90 - 1,500			
21	Meter Accuracy	Percentage of meters that pass side-by-side/dual pan meter tests (BGE Only)	Sample Size Population Based on 95% Confidence Level and a 5% Confidence Interval. Proposed Tolerance Level +/- 2% # of Dual Pans within tolerance divided by total number of dual pan installs.	123	100	256	250	
22	Meter Accuracy	3rd Party Accuracy Test Percentage	Report from vendor - plan now is to import those results into MTS - meter test system in the EMC test shop	98%	99%	96%	99%	
23	Meter Accuracy	AMI Meter Sample Internal Test Results	• A sample of meters (determined by ANSI Z1.4) will be tested prior to releasing a shipment into inventory for installation • Solid state electric meter accuracy of X% will be required	99%	99%	99%	99%	
24	Meter Reading Effectiveness	Percentage of interval reads received	# of intervals reported / total number of possible intervals to be reported * 100	99%	99%	99%	99%	
25	Awareness and Understanding	% awareness of AMI technology and benefits (survey measurement)	3rd Party Survey	98	99%			

Operational metrics commentary

- The Phase one Operational metrics are inline with expectations

Advanced Metering Infrastructure Performance Metrics Report

#	Metric Category	Key Metric	Calculation	Results Q4 2012	Target Q4 2012	Results Project to Date	Target Project to Date	Comment
Communication & Education Metrics								
26	Awareness and Understanding	% understanding of AMI technology and benefits (survey measurement)	3rd Party Survey	82%	85%			
27	Community Outreach	# of community outreach events conducted and number of attendees at events	Count of events and number of attendees	74%	75%			
28	Community Outreach	# of articles that appear in local media	Count of articles that appear in local media as a result of company issued press releases	Conducted - 6 Attendees - 2,100	Conducted - 6 Attendees - 2,000	Conducted - 30 Attendees - 11,520	Conducted - 30 Attendees - 10,000	
29	Community Outreach	# of articles in internal newsletter	Count of articles in internal newsletter	8		23		
30	Customer Satisfaction	# of Meter Installation Complaints/Claims	Count of Meter Installation complaints/claims	12	12	42	40	
31	Customer Satisfaction	# of missed installation appointments	Count of missed appointments	Damaged Property - 5 Inaccurate Meter - 6 Other - 2		Damaged Property - 21 Inaccurate Meter - 35 Other - 15		
32	Community Outreach	# of customer organizations contacted	Count of customer organizations contacted	12		35		
33	Customer Satisfaction	# of customer referrals to energy advisors	Count of number of referrals	15		19		
34	Community Outreach	# of customer communication methods deployed	Count of number of items	52		172		

Communication & Education metrics commentary

- The Communication & Education metrics are in line with the expectations disucussed in BGE Communication Plan previously filled with the commission