STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 09-M-0074 - In the Matter of Advanced Metering Infrastructure.

NOTICE SEEKING COMMENT

(Issued April 14, 2009)

On February 13, 2009, the Commission issued an order in this proceeding in which, inter alia, it found that, to address the need for greater consistency in the benefit-cost analysis used by New York utilities, a process is needed to examine the key aspects of advanced metering infrastructure (AMI) benefit-cost analysis, culminating in guidance to the utilities on the methodology to be used to calculate benefits and costs. The Commission, therefore, directed the Staff of the Department of Public Service (DPS Staff) to develop a generic benefit-cost approach for evaluating AMI. DPS Staff's "Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure" (Proposed Framework) is attached to this Notice. DPS Staff will organize workshops with the active parties in this proceeding to further refine the Proposed Framework. DPS Staff will work with parties to attempt to build consensus on the Proposed Framework before parties file comments, in order to narrow the scope of outstanding issues.

NOTICE is hereby given that parties may file comments on DPS Staff's generic benefit-cost framework. Parties may comment on this generic approach until June 15, 2009. Comments must be served by e-mail on all active parties in this proceeding and also be addressed to secretary@dps.state.ny.us. A hard-copy must also be submitted to Jaclyn A. Brilling, Secretary to the New York State Public Service Commission, Three Empire State Plaza, Albany, New York 12223-1350.

(SIGNED) JACLYN A. BRILLING
Secretary

Department of Public Service

CASE 09-M-0074 – In the Matter of Advanced Metering Infrastructure.

Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure

April 14, 2009

Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure

Background

The Commission's February 13, 2009 Order adopted minimum functional requirements for advanced metering infrastructure systems (AMI), and stated:

> To address the need for greater consistency in the benefit-cost analysis used by New York utilities, we believe a process is needed to examine the key aspects of AMI cost-benefit analysis, culminating in guidance to the utilities on the methodology to be used to calculate benefits and costs. We are therefore directing Staff to begin such a process by developing a generic approach to the AMI benefit-cost analysis and issuing it for party comment no later than 60 days from the date of this order.[1]

In its December 19, 2007 Order in Docket 94-E-0952, *et al.*, the Commission directed supplemental filings that include: "[a] revised benefit-cost analysis, using updated estimates of benefits and costs, and performed according to the practices and procedures customarily utilized in the economic analysis of energy efficiency programs."[2] On June 23, 2008, the Commission adopted "Efficiency Program Selection Criteria",[3] which are attached as Appendix 4. The Efficiency Program Selection Criteria provide the basis of Staff's proposed framework for examining AMI projects; however, utilities proposing an AMI implementation should concentrate their efforts on the following calculations: the Benefit Cost ratio under the Total Resource Cost (TRC) test, the TRC plus Carbon test, and the Electric and Gas Rate Impacts. Appendix 4 highlights those criteria as most important for this review. In addition, while the EEPS criteria concentrate on savings by 2015, this analysis should concentrate on the benefits over the life of the meters.

This Benefit Cost framework further is informed by the work of the California Public Utilities Commission and California Energy Commission in developing a Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure. Since California's framework was developed, many utilities have filed plans for AMI roll outs. California's three largest utilities used the California framework as the basis of their filings. The Public Utility Commission of Texas has adopted a spreadsheet-based tool[4] as its framework for the filing for cost recovery of Advanced Meter Systems.[5] The Vermont Department of Public Service Board

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1 Case 09-M-0074, In the Matter of Advanced Metering Infrastructure, Order Adopting Minimum Functional Requirement for Advanced Metering Infrastructure Systems and Initiating an Inquiry Into Benefit-Cost Methodologies, (issued February 13, 2009) p. 21 (the AMI Functionality Order).

2 Case 94-E-0952, et. al., In Matter of Competitive Opportunities Regarding Electric Service, Order Requiring Filing of Supplemental Plan, (issued December 19, 2007), p. 21. This requirement was rescinded in the February 13, 2009 Order (Supra), in light of the Commission's decision to initiate this inquiry into benefit-cost methodologies.

3 Case 07-M-0548, Energy Efficiency Portfolio Standard, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs, (issued June 23, 2008), Appendix 3.

4 The Texas AMI Business Case analysis tool was developed by McKinsey & Company and is publicly available at http://www.mckinsey.com/clientservice/electricpowernaturalgas/service_ami_download.asp#download

5 PUCT Project No. 33874, From for Transmission and Distribution Utility Advanced Metering Infrastructure Surcharge, Order Adopting the Development of the Electric Utility Advanced Metering Infrastructure Surcharge Form Required by PUC Subst. R. 25.130(k)(3), (issued June 22, 2007).

in its investigation into smart metering and time-based rates[6], employed consultants to conduct a Benefit Cost Analysis for Advance Metering and Time-Based Pricing[7] for utilities of Vermont. Cost areas reflected in these studies are nearly identical. The costs and benefits laid out here are meant to be all-inclusive and so all may not apply to all utilities. Each utility should consider all the costs and benefits only as they apply to that utility's AMI or Advanced Meter Reading (AMR) implementation.

Staff proposes the framework for Benefit-Cost analysis described in this document, laid out within the following sections:

1. Description of the Scenarios to be analyzed in the Benefit-Cost Analysis
2. Common Categories of Costs to be Included in the Analysis
3. Common Categories of Benefits to be Included in the Analysis
4. Common Analysis Parameters for each of these Cases
5. Rate Choices to be Offered in the Demand Response and Demand Response + Reliability Case
6. Methods for Estimating and Valuing Demand Response

The process begun by the issuance of this document is designed to yield a methodology for benefit-cost analysis that is robust, is consistent across New York's utilities and reflects the input of interested parties. Staff will organize workshops with the active parties in this proceeding to further refine this Proposed Framework. Staff will work with parties to attempt to build consensus on the Proposed Framework before parties file comments, in order to narrow the scope of outstanding issues.

Some of the key inputs to a benefit-cost analysis, in particular the estimates of the demand response that can be expected from customers that face time-differentiated price signals, are not yet sufficiently known. Several New York utilities have proposed AMI pilot programs whose goals include the development of better estimates of customer demand response, among other information needs. The results of the pilots will therefore become important inputs to the benefit-cost analyses of proposals for full AMI deployment. Pilots, therefore, can and should move forward while the benefit-cost framework is being developed. Staff's expectation is that the pilots will be developed in such a way that they recognize the likely information gaps in a benefit-cost analysis and will be designed to fill those gaps.

Section 1. - Description of the Scenarios to be Analyzed in the Benefit-Cost Analysis

In the AMI Functionality Order the Commission found:

> One important consideration in benefit-cost modeling is the base case scenario. In order to accurately assess AMI's cost-effectiveness, we must compare AMI to alternative

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6 Vermont Public Service Board Docket No. 7307.

7 Freeman, Sullivan & Co. and MW Consulting, Benefit Cost Analysis for Advance Metering and Time-Based Pricing –Final Report, March 26, 2008. available at http://www.state.vt.us/psb/document/ElectricInitiatives/SmartMetering.htm

approaches for obtaining operational savings and/or residential demand response. The true value of AMI can't be determined by comparison to solely a mass market "do nothing" scenario. In particular, an alternative scenario should be evaluated using AMR for labor savings, plus expansion of direct load control targeted to high potential customers for mass market demand response, in concert with extension of the MHP program for commercial-industrial customers.[8]

Consistent with the Commission guidance, utilities should estimate the capital and operational and maintenance (O&M) costs of the metering, billing, and communication systems infrastructure for three scenarios:

• Business as Usual
• Full Scale AMI Rollout
• Full Scale AMR Rollout with targeted Direct Load Control

An overview of the costs and benefits that should be included in each case is presented below.

1. Business as Usual Case – This case should include the expected capital and O&M costs associated with maintaining the current metering, data collection and validation, billing, customer information systems, system operation, and communication systems for all customer classes. This business as usual case should include measures taken to meet the Commission's goals for energy efficiency, renewable energy, and reductions to transmission and distribution losses. Costs to support Mandatory Hourly Pricing (MHP) should be reported separately. The assumed expansion of MHP should be limited to plans already approved by the Commission. This analysis should include any currently planned upgrades to the metering and billing systems for the period 2009 to 2030. For example NYSEG has current plans to replace its electromechanical time of use (TOU) meters with solid state electronic meters to reduce the cost of resetting TOU clocks after power failures. If National Grid were to file a Benefit-Cost analysis its "business as usual case" would be its current AMR system. These costs should be estimated on an annualized basis for the analysis period.

2. Full Scale Rollout of an Advanced Metering Infrastructure – This scenario should estimate the costs and benefits of designing and implementing an advanced metering infrastructure that serves all existing customers. Any cost or benefit synergies with the MHP program should be identified. This case should include a description of how the utility plans to phase the meter installation. This system should support the applications and functional requirements discussed in Section 3.

    a. Costs - This analysis should include the expected start up and capital costs of designing, purchasing, and deploying the advanced metering infrastructure and the annual expected costs of maintaining and operating this system from 2009 through 2030. The analysis should clearly specify the costs anticipated at each stage of the deployment cycle-- system design and testing, beta testing of the interface between

8 Id. pp. 20-21.

billing and metering systems, and any other milestones between rollout and the completion of meter installations and integration into the network

b. Benefits - This analysis should include an estimate of the present value of the potential benefits identified in the benefit cost section below over the same analysis period specified above. Utilities should also provide a qualitative discussion of the AMI system benefits for those benefits which a dollar value cannot be estimated. Benefits should all be calculated relative to the baseline conditions expected in the business as usual case.

3. Full Scale Advanced Meter Reading (AMR) Rollouts with targeted Direct Load Control (DLC) – This analysis should include a description of the rollout of a least-cost AMR system with targeted DLC by the utility and the rationale for choosing the subject case. Utilities need to explicitly specify the criteria used to design AMR with DLC roll out. Examples of such a scenario may include: identification of the extent of the current meter stock that could be covered by such a system; identifying the potential for demand response from DLC; and identifying a cost effective threshold down to which MHP could be expanded.

   a. Costs - This case should include the startup and capital costs of designing, purchasing, and deploying the AMR infrastructure and the annual expected costs of maintaining and operating this system from 2009 through 2030.

   b. Benefits - This section should include annualized estimates of the benefits expected to accrue during the rollout to both the customers who receive the new meters and any system wide benefits such as reduced procurement costs that will be spread to all customers. This discussion should explicitly specify whether or not the expected operational benefits from a full scale roll out of an AMI system can be captured through a roll out of AMR and DLC. The analysis should also specify the size of the potential market for DLC and the how the demand response benefits of a DLC program would compare to options available with an AMI system.

Section 2. - Common Categories of Costs to be Included in the Analysis

The recommended framework for business case analysis by the California Public Utilities Commission identified 82 specific cost categories (Appendix 1), which fit into the following categories and are in line with costs identified by other utilities[9]:

- **Meter System and Installation –** The total costs of all electric and gas meters and associated hardware and software, including design, installation, testing, maintenance and salvage/disposal of removed meters. Costs for AMI rollout will primarily be driven by the technical capabilities of the meter according to the specified functional requirements. While the Commission's Minimum Functionality order defines a minimum of what is

9 CPUC and CEC, Chavez, Moises and Mike Messenger , *Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure.* Draft Report, April 14, 2004.

expected of meters, utilities may propose more robust criteria in order to meet future needs.

- **Communications System –** This infrastructure facilitates the communication of data from the meter to the utility and back through wide and local area networks. The type of system installed will be influenced by customer density, topography of service territory, available facilities, and necessary volume of data to be transported. AMI communication systems technologies must be capable of being economically scaled up (or down) in response to future data needs, such as those associated with the Smart Grid. Consistent with the Commission's Minimum Functionality order, communication systems must use open protocols and the development of costs should explicitly consider the use of existing public networks and commercially available broadband solutions.

- **Information Technology (IT) and Application** (**Meter Data Management System) –** Costs of the system hardware and software and integration into existing IT environments. Also includes cost of creating a central repository for data inflow and facilitating data flow to all the utility's systems and to customers. AMI brings an exponential growth in data collection; unlocking the value of that data depends on the utilities' ability to process, access, and use that data. Utilities need to specify the key factors associated with their decisions to upgrade existing IT systems, completely replace them, or outsource the entire process of delivering electronic reads for billing customers. If possible the costs of alternative options for billing/data management should be specified.

- **Customer Services –** Costs required to deliver information and education about new rates, programs and tools available to customers. This category may include costs for outbound communications for critical peak pricing or other rate notifications.

- **Management and Other Costs –** Miscellaneous costs required to manage the implementation of a project of this magnitude. Utilities must describe in detail how such costs are separate from and incremental to costs incurred in normal business operations.

In the AMI and AMR scenarios the cost estimates should be grouped into the following cost categories, so that they can be staged throughout the AMI study period:

1. Capital costs (design, contracting, training, hiring temporary installation crews, purchase and installation of advanced meters, installation and testing at customer premise, new software, communications networks, etc.)

2. O&M costs (cost of reading meters, translating data to bills, sending bills out and managing the network, etc.)

<u>Cost Estimation Methods</u>

The methods listed below should be used by the utilities for quantifying AMI and AMR costs. This list is taken from the California Framework and should be viewed a starting point for the discussion of preferred estimation techniques. These methods are listed in order of preference and should be used in this order, unless a method is not applicable or the specific data are not available, in which case the next method in order on the list would be the preferred method. The utilities may use more than one method for a particular item.

C1. “Actual” – Record results following implementation, at the utility in question, of a pilot or large-scale program, quantify impacts based on results, then multiply by a dollar value for the cost.

C2. “RFP” – Obtain cost estimates from vendors/suppliers via a Request for Proposal process. This may be for purchase of hardware, software, or services.

C3. “Benchmark” – Estimate costs utilizing utility resources to perform a specific activity or provide a specific function. Use as inputs into that estimate data from other utilities that have implemented large-scale advanced metering infrastructure (AMI) or, where applicable, automatic meter reading (AMR) projects. Data from other utilities may be obtained directly from those utilities or from vendors or consultants who implemented the projects. AMR-project data would be applicable only for field activities related to meters, such as pickup meter reads, meter installation, panel replacements, and meter O&M.

C4. “In-house” – Estimate costs utilizing utility resources to perform a specific activity or provide a specific function, but not using inputs from other utilities. This would be the case for existing utility communications or information technology infrastructure where inputs from other utilities are not likely to be relevant. For example, a utility might own a fiber optic communications system for use in communications or have a particular meter asset management software system.

C5. “Indirect Benchmark” – Estimate costs related to indirect implementation costs, such as damage claims, using utility historical records plus data from other utilities that have implemented large scale AMI or AMR projects, adjusted for utility-specific conditions.

Section 3 - Review of Benefit Categories to be Included in the AMI analysis

The California Framework identified four major categories of benefits (Appendix 2):

- System Operations Benefits
- Customer Service Benefits
- Demand Response Benefits
- Management and Other Benefits

Each benefit category is discussed below. Staff has reviewed California’s list and adopted it here with added comments on our understanding of these benefits and with additional benefits that may be attainable from AMI or AMR systems. Staff proposes to conduct workshops with parties to further define and develop methods of quantifying these benefits.

System Operation Benefits

1 Reduction in Meter Readers, Mgmt & Admin Support (and associated costs) AMI would eliminate on-cycle manual and mobile meter reading and associated costs. The benefit value includes all direct meter-reading labor expense, supervisory labor expense, vehicles, equipment, associated building leases, and other miscellaneous materials. Also included are O&M/upgrade expenses for current meter-reading devices and yearly salary increases for meter readers and supervisors.

2 Field service savings (turn-on's / turn-off's) AMI will enable utilities to avoid field service visits triggered by questionable estimated readings on customer move-outs/move-ins, reducing field service personnel costs.

3 May provide ability to identify active accounts for metered accounts not being billed, broken meters, wrong multipliers Identification of these billing problems should increase revenues. While this benefit could be counted in a rate impact analysis it would not be applicable to a TRC test.

4 Some energy theft easier to identify Reduction of energy theft can improve equity for customers because it reduces the cost of energy theft to customers not stealing power. It may also enhance the revenues of the utility. While this benefit could be counted in a rate impact analysis it would not be applicable to a TRC test.

5 Phone Centers - Reduced call center personnel in the long term due to anticipated lower customer call volume (due to estimated / disputed bills) Estimated meter reads often generate customer calls associated with billing issues, with monthly, daily, or more frequent reads from AMI, these missed reads and associated estimated bills can be reduced, thereby decreasing customer call volume, call duration time, and call center agent time spent handling these billing inquiries. Customer Service Representatives' access to on-demand power quality data or power loss flags could reduce call-handling time for power quality-related calls. With direct access to up-to-date usage data, customer usage inquiries can be handled promptly, without needing a premise visit to collect information.

6 Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change Because all customers will have interval meters, customers changing service to TOU or other dynamic rates would not need to have their meter replaced. The change could be done with a change to billing system or meter program.

7 Outage management benefits AMI outage restoration reporting functionality can be expected to reduce total time for service restoration, thus reducing the time customers are out of service and the possibility of lost revenue during outage events. Additional strategic benefits (e.g., improved regulatory response, improved customer satisfaction, and public perception) would also be expected to accrue but are more difficult to quantify. AMI can be used to more effectively dispatch service crews for premises-level outage restoration, particularly when customers are affected by multiple-cause events. For instance, a fault can create an outage that affects many customers. Upon correction of the fault, the utility may incorrectly assume that all affected customers are restored. However, there can be occasions where an additional failure occurred during the outage that affects only a subset of originally affected customers. In situations like these, AMI provides the utility with the ability to determine the status of service to a customer's meter. Therefore, the additional crew field time associated with these restoration activities, which may include a re-dispatch to the area, can be reduced. With real-time voltage sensing capability, AMI can provide system dispatchers with the ability to reduce unnecessary single-call trouble dispatches that are due to issues that can be isolated to the customer's side of the meter. When calculating the outage management benefits for the TRC test, reductions to lost revenue would not be included but reductions to consumer's cost of lost productivity and food spoilage would be included in the TRC test. Reduction to lost revenue would be included in the Rate Impact analysis.

8 Better meter functionality / equipment modernization New AMR or AMI meters may perform better than the meters they replace, with greater accuracy and lower failure rate. New meters may capture and report power quality metrics that could be used by the utility to better manage its network.

9 Remote service connect / disconnect With the installation of a service switch and load limiting device, the AMI-enabled meter would give the utility the means to shed or limit electric loads by remote command. The device can be triggered on a particular part of the utility's network as a contingency to reduce the potential for system outages or network stress during crisis situations. Utilities may realize cost savings and be able to improve network reliability if the electric meter included this additional device. While utilities in other jurisdictions have described the benefit of reducing the time and cost of shutting off power to for non-payment, we remind the companies that termination of service for nonpayment is subject to Home Energy Fair Practices Act (HEFPA) regardless of whether that disconnection is performed by physical (on site) or electronic (remote) service shut off. No utility may utilize AMI for remote disconnection of service for nonpayment unless it has taken all of the prerequisite steps required by HEFPA, including the requirement of 16 NYCRR §11.4(a)(7) that customers must be afforded the opportunity to make payment to utility personnel at the time of termination. This process requires a site visit, even where a remote device is utilized.

10 Meter accuracy Evidence shows that electro-mechanical electric meters begin to under-record with age due to the wearing of the moving parts. Solid-state electric meters do not generally have this problem, and, therefore, average meter accuracy will improve as electro-mechanical meters are replaced. While this benefit could be counted in a rate impact analysis it would not be applicable to a TRC test.

11 System planning design efficiency – Deploying AMI can allow more sophisticated load analysis which can result in more "right sizing" of assets (to prevent over or under investment in a new asset or monitor load on existing assets). These benefits could be seen in substation and transformer sizing and circuit maintenance.

Customer Service Benefits

12 Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs" AMR/AMI system can enhance productivity because reducing the instances of unread meters resulting in estimated bills. AMR/AMI provides improved meter read accuracy, which can reduce costs associated with estimated and inaccurate reads, and the ability to confirm meter operability remotely. Reducing the number of estimated bills can reduce the cost to handle bill-related investigations and complaints outside the call center. Utilities should be careful not to double count these benefits with benefits laid out in benefit No. 5.

13 Early detection of meter failures - Solid-state meters fail more conspicuously than electro-mechanical meters and are, therefore, more readily identified. However, because the Companies are already systematically replacing electro-mechanical meters with solid-state electric meters, this benefit would be decreased annually based on the average number of electromechanical meters that would have otherwise been replaced. While this benefit could be counted in a rate impact analysis it would not be applicable to a TRC test.

14 May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, identify any unsafe conditions This benefit may be outweighed by the loss of regular inspection of the meter by meter readers.

15 Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing Respondent should be careful not to double count these benefits with benefits laid out in benefit No. 5 and No. 12.

16 Customer energy profiles for Energy Efficiency / Demand Response targeting (marketing) – Analysis of customer load patterns could be used to determine candidates for certain EE and DR programs. More targeted marketing of EE and DR programs could lead to higher enrollment in these programs.

17 Customer rate choice / new rate options

18 Customized billing date - Because AMI systems collect meter data more frequently, AMI would allow utilities the ability to let customers choose their billing date. This benefit is hard to quantify but it may lead to less delinquency and better cash flow from customers.

19 Energy Information – A recent survey of customer feedback devices[10] found that studies have shown a conservation affect of 0 to 18% from the use of devices that give customers information on their energy use. A TRC test would net the cost of the energy save with the customers cost of a feedback device.

20 Enhanced billing

21 Load Survey AMI can provide data that can be used for load research studies, thereby decreasing the need for more costly load research metering equipment and services, such as telephone lines and costly field maintenance.

22 On-line bill presentment with hourly data / more timely and accurate information about electricity / info access - AMI and supporting systems can help increase customer utilization of the utility's internet site and on-line bill pay services and decrease overall customer service costs. By supporting the provision of daily and interval energy data via an Internet portal for customer

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10 Neenan, Bernie, EPRI Project Manager, Residential Electricity Use Feedback: A Research Synthesis and Economic Framework, Final Report February 2009.

viewing, AMI may be expected to increase customer interest in and use of the utilities internet site and on-line bill pay services for other purposes.

23 Lower customer bills Customers given the option of dynamic rates may be able to change their rate and lower their bill without changing their usage pattern. This savings would not be counted under TRC test.

24 Value to customers of more timely & accurate bills

Demand Response Benefits

25 Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions AMI can provide increased visibility to energy consumption data to facilitate customer acceptance and increased participation in dynamic pricing and load management programs. For example, two-way communications can enable notification of prices or demand response events (either day-ahead or otherwise) to customers that can then take manual or automatic load reduction actions. This increased load management participation and associated peak load reduction is expected to result in the avoidance of capacity and peak energy procurement (or postponement of generation construction requirements) costs that would otherwise be required to serve peak load. Reductions in wholesale market clearing prices may also result, although they would not be counted under TRC test, but could be counted in a rate impact analysis.

26 System reliability adder (capacity buffer)

27 Dynamic fuel switching / Dynamic integration of conventional and distributed supplies

28 Avoided / deferred transmission and distribution (T&D) additions / upgrade costs - AMI can provide increased visibility to energy consumption data to facilitate customer acceptance and increased participation in load management programs. For example, two-way communications can enable the Companies to signal customers to take voluntary, manual load reduction actions or to automatically adjust customer equipment. While AMI does not provide the Companies with the ability to postpone every specific T&D project, the increased load management participation and associated peak load reduction will generally help to defer T&D work over the long run.

Management and Other Benefits

29 Reduced equip and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.) Deployment of AMI would defer the capital costs associated with replacement of meters and other manual meter-reading equipment (e.g., vehicles) that would otherwise have been required.

30 Reduced miscellaneous support expenses (including office equipment and supplies) Utility costs for workers' compensation associated with injuries incurred by employees during meter reading can be reduced upon adoption of an AMR/AMI system, as meter readers would no longer be exposed to high crime areas, dogs, fences, adverse weather, etc. Costs associated with vehicular accidents occurring during travel between meter-reading locations in the field and utility premises would also be eliminated with AMI systems.

31 Reduced battery replacement / calendar resets / meter programming – When the power goes out to electromechanical TOU meters, the meter's calendar will go out and will need to be reset by the meter reader. AMI meters can be reset or reprogrammed remotely.

32 Reduced meter inventories / inventory management expenses due to expanded uniformity

33 Summary billing cash flow benefits (existing customers) – AMI could synchronize the reading of customer's meters for customers who receive summary bills of multiple premises and meters that may not be on the same meter reading schedule. Synchronizing these multiple bills would reduce the time to get bill out to customer and speed payment of bill.

34 Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes With the ability to perform daily or more frequent readings, consumption from premises that are supposed to be unoccupied can be more quickly identified and addressed. This is expected to limit utility exposure to write-offs of charges for consumption registered on "inactive" advancing meters on accounts closed after customers inform the utility they are moving out. This would not be counted in a TRC test.

35 Possible new revenue source / new business ventures / new products & services / web based interval & power-quality data

36 May facilitate ability to obtain GPS reads during meter deployment-improving Franchise & Utility Users Tax processes – By associating every meter with its exact geographic location, the utility can more accurately manage franchise fees and local government taxes associated with that location.

37 Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs

38 Potential for Federal investment tax credits While any tax benefits would not be included in a TRC test, they would be included in a rate impact analysis.

39 Environmental - By facilitating greater customer participation in load reduction and demand management programs, AMI can help reduce peak loads coincident with the Companies' system peaks. This reduction in peak load, in turn, displaces generating units' run-time, thereby decreasing the amount of pollutants discharged by peaking units. The cost of $15 per ton of carbon should be used for this calculation as decided in the EEPS case.

New York Independent System Operator (NYISO) Benefits

40 Shortened Settlement Process – With more frequent meter reads, wholesale market participants should have access to more current and accurate customer consumption data. This should allow the wholesale settlement process to be shortened by reducing the estimates and adjustments to customer consumption needed settle markets currently. This is a long term benefit that is only achievable if all utilities adopt an AMI system.

41 Elimination of Many Manual Billing and Auditing Processes –With accurate and timely consumption data, billing and collections by the NYISO should be more streamlined and auditable. This is a long term benefit that is only achievable if all utilities adopt an AMI system.

42 Reduced Cost of Collateral For Market Participants – If the settlement process can be shortened, lower levels of collateral will be needed by the NYISO from market participants. This is a long term benefit that is only achievable if all utilities adopt an AMI system.

Benefits Estimation Methods

This list is taken from the California Framework and should be viewed a starting point for the discussion of preferred estimation techniques. Methodologies for quantifying the Benefits of AMI and AMR systems:

B1. "Actual" – Record impacts following implementation, at the utility in question, of a pilot or large-scale program, quantify impacts based on results, extrapolate based on the planned scope of deployment, then multiply by a dollar value for the benefit.

B2. "Benchmark" – Estimate savings using recorded utility operating costs and anticipated reductions in those operations, utilizing data from other utilities that have implemented large scale AMI or AMR projects and adjusted for utility-specific conditions. Such data may be obtained directly from those utilities or from vendors or consultants who implemented the projects.

B3. "Benchmark, Unit-based" – Estimate benefits by quantifying number of instances of an occurrence or quantifying a level of performance based on historical utility operating data, then multiplying by a dollar value for the benefit. Inputs include utility operating records and data from other utilities that have implemented large scale AMI or AMR projects and adjusted for utility-specific conditions. Such data may be obtained directly from those utilities or from vendors or consultants who implemented the projects.

B4. "Substitution" – Estimate benefits by utilizing historical utility accounting data and summing the value of those activities and systems that will be superseded by AMI.

B5. "Qualitative Benchmark" – Some benefits are not quantifiable but will be described qualitatively, utilizing data and information from other utilities that have implemented large scale AMI or AMR projects.

B6. "Qualitative" – Some benefits are not quantifiable but will be described qualitatively, but without using data and information from other utilities that have implemented large scale AMI or AMR projects.

Section 4 - Common Analysis Parameters for each of these Cases

The following analysis parameters should be used consistently across each of these cases:

1. Duration of benefit-cost analysis periods – 2009 to 2030;
2. Discount rate equal to 5.5% in nominal terms[11];
3. All costs and benefits should be presented in annualized values in work sheets and then converted to present value in 2008 dollars;
4. Utilities should use the avoided cost of electricity, capacity and natural gas that were adopted in the Jan. 19, 2009 EEPS order, attached as Appendix 3. To the extent these costs are revised in any subsequent Commission Order, the revised estimates should be used.
5. Minimum functionality of AMI system as set out in the AMI Functionality Order.

Staff has not made any common assumption on meter life. This input should be decided based on the warranties and representations made by the meter manufacture selected by utilities.

Section 5 - Rate Choices to be Offered to Customers

In the EEPS Case, Working Group VIII was formed to address Demand Response issues. The group was composed of DPS Staff, Utilities, Demand Response Providers, ESCOs, and other parties. It provided the following recommendation on dynamic pricing:

> The Commission should encourage Program Administrators to work jointly to test three dynamic pricing options: 1) TOU that has a peak period that is narrowly focused to address the system peak; 2) a voluntary residential Real Time Pricing (RTP) with prices based on real-time wholesale energy market prices; and 3) a peak time rebate program that would give customers rebates for reducing their consumption during system peak.[12]
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> The purpose of such a joint effort would be to get a better understanding of the benefits and cost effectiveness of such tariffs in New York. Some lessons learned from other pricing pilots that should guide Program Administrators in designing and testing these dynamic prices are:
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> - Load control devices can double DR but the technology should be tested to make sure it works as expected. The Westchester pilot relied on customer behavior to shift load to lower priced periods of the day. The test should incorporate some forms of direct load control to determine if greater net benefits are achieved with direct load control devices.
> - A significant portion of the New York retail electric market is served by Energy Service Companies (ESCOs) that have provided dynamic prices. A methodology for retrieving load data and sharing it between ESCOs, DR providers, and Transmission Owners (TOs) should be tested in a pilot.

11 This is the discount rate used by DPS Staff in the EEPS case.

12 Case 07-M-0548, Supra, Working Group VIII – Report Demand Response and Peak Reduction, October 17, 2008, p. 23

- If an ESCO customer’s electric usage is measured by hourly meters, then the ESCO needs to be billed on their customer's actual load shape instead of a class average load shape. Using a class average load shape takes away any incentive the ESCO has to do Energy Efficiency and DR by not giving the customer or the ESCO credit for altering their load shape.

> Program administrators should work collaboratively with the Commission Staff and the EAG to determine a common understanding of the "benefits" of dynamic pricing, so that it can be properly valued and used by TOs to evaluate advanced metering proposals.

Staff endorses this recommendation of the general rates that utilities should test. Staff further recommends that the last suggestion, that ESCOs should be billed on the hourly load of their customers, be altered to allow ESCOs to choose for each customer whether the ESCO is billed on class load shape or the customer’s hourly load.

Section 6 - Methods to Estimate and Value Demand Response

Estimations of the load impacts from the deployment of AMI, and its associated rates and/or automated load control devices, are a function of several factors, including the assumed levels of participation in rate options, price elasticities, and the price differential between peak and off peak prices. While some work to test the demand response impacts of different rates and technology has been completed,[13] there has been little experimentation in New York to validate the results of other regions. Models like the Brattle Group’s Pricing Impact Simulation Model (PRISM) Suite[14] and the analysis of Freeman, Sullivan & Co.’s analysis[15] of Vermont utilities, project the net present value of demand response from dynamic pricing programs base on results of California’s Statewide Pricing Pilot, adapted to local climate and central air-conditioning penetration rates. Pilots proposed by New York utilities may help to build confidence in the estimates of the value of demand response available from AMI.

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13 See for example Faruqui, Ahmad and Sanem Sergici, Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence, January 10, 2009, available at http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf

14 See footnote 4 for link to model.

15 See footnote 7 for link to report.

Appendix 1

AMI Potential Costs List

AMI Potential Costs List

Meter System and Installation

1 Cost of purchasing meters, comm modules and related vendor support equipment & software
2 Installation labor (incl workers comp, P&B, payroll taxes, etc.)
3 Installation and testing equipment costs (tools, equipment and vehicles)
4 Administration of contracts / supervision of installer workforce
5 Meter installation tracking systems (Endpoint Link-other), Meter info / records admin / GPS
6 Panel reconfiguration / replacement costs (A base, other) / Meter socket repairs
7 Potential customer claims related to damages during meter installation and/or panel upgrades
8 Additional temporary meter reading staff for transitional period / mtr reader transition costs
9 Supply chain management including development of staging facilities, shipment & handling of new meters
10 Salvage / Disposal process for removed meters
12 Training (meter installers, handlers, shippers)
13 Additional costs to O&M / more complex metering & comm infrastructure (labor, tools, equip, vehicles)
14 Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)
15 Pickup reads (remote retrieval not available / possible)

Communication System

16 Establishing backhaul strategies and contracts (including contracts with public networks)
17 Physical and logical security, securing data transmission, infrastructure to support security, etc.
18 Costs of backhaul contracts and services
19 Site surveys to determine placement of network equipment
20 Purchase network communications equipment and hardware
21 Development of communications link from meters to data center, LAN / WAN / servers for storage & processing
22 Staging facilities for WAN / LAN equip and mounting hardware (pre-installation)
23 Training for installation of WAN / LAN equipment (including install labor for wireless circuits)
24 Mapping of network equipment on company facilities (asset facility mapping)
25 Installation of LAN / WAN equipment (including bucket trucks / crews)
26 Dispatching and O&M of field LAN / WAN and infrastructure equipment
27 Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)
28 Development of Internet based usage data communication
29 Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).
30 Cross arms (e.g. streetlight arms for pole top installations) and other mounting
31 Pole replacement - to "fit" concentrators
32 Electric power consumed by LAN / WAN equipment and/or meter modules

Information Technology and Application

33 Computing system implementation in data center (new hardware / software, IT security review & compliance)
34 Network planning and engineering - coverage studies, technology selection, field testing & engineering
35 Update work management interface to process additional volume of meter changes, data scripts
36 New information management software applications
37 Development and installation of interfaces to core utility systems (CIS, EMR, OMS, OIS, EAI, SAP, etc.)
38 Develop and process dynamic rates in CIS billing systems
39 Exceptions processing (develop, update, and execute data cleanup routines)
40 Ongoing IT system operations & O&M (usage, software, internet application)
41 Ongoing data storage and handling costs / incl test, QA environments, business continuity, disaster recovery
42 Server replacements (every 3-4 years) for 15 year life cycle
43 Records - databases, drawings of field network and data center servers
44 Aggregating, validating and creating billing determinant data for electric billing
45 Data center facilities
46 Data center system performance monitoring and management

Appendix 1

Customer Services

47 Customer education of rate changes/ customer communications campaign
48 Out-bound communications (mass media costs, e.g., print, radio, TV) . /CPP or other rate notifications
49 Additional rate analysis due to multiple TOU options.
50 Customer records/ billing and collections work associated with roll-out of meter change process
51 Increased call center activity during transition from existing to new rates / meter change appointments
52 Process meter changes for new meter installations and DA accounts
53 Customer support for internet based usage data communication
54 Modification and customer support costs for OIS and other system changes
55 Cost of complying w/ regulations - providing alternative safety measures (due to removal of electric mtr readers)

Management and Other Costs

56 Overall project mgmt costs (and overhead) including customer service, IT and other functions
57 Buy out of Current Meter Contract
58 Impacts of early removal of assets(existing meter inventory – stranded investment)
59 Cost of stranding existing utility systems (legacy systems, other)
60 Risk contingencies (e.g., technology obsolescence / reliability)
61 Meter RFP process and contract finalization and administration
62 Employee training for deployment and O&M of new systems, rate structures, etc
63 Training for other traditional classifications (records, call centers, meter readers, T-men, etc)
64 Work management tools
65 Meter reader reroute administration (assuming gas meters are not included- will continue to be read)
66 Recruiting of incremental workers
67 Supervision / overhead of contracts and technology personnel assigned to hardware and systems development
68 Employee communications and change management
69 Customer acquisition and marketing costs
70 Capital Financing costs (if not included in purchase cost)
71 Cost of increased load during mid-peak and off-peak periods
72 Cost of shifting costs from C&I customers to individual ratepayers
73 Customers access to usage information through communications medium

Gas Service Impacts (If included)

74 Gas Index / Module Purchase
75 Aggregation / Validation of monthly / hourly reads for gas billing
76 Replacement of gas meter module, battery purchases and replacement labor
77 Warehousing operations for gas modules
78 Performing atmospheric corrosion inspections (currently performed by meter readers)
79 Energy diversion or safety inspection of service and meter facilities on some periodic basis(currently MRs)
80 Purchase / replacement of non-retrofittable gas meters
81 Increased O&M on gas meters /modules due to addition of electronic modules
82 Cost of complying w/ regulations- providing alternative safety measures (due to removal of gas meter readers)

AMI Potential Benefits Categories

System Operation Benefits
1 Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)
2 Field service savings (turn-on's / turn-off's)
3 May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers
4 Some energy theft easier to identify
5 Phone Centers - Reduced FTEs in the long term due to anticipated lower cust call volume (estimated / disputed bills)
6 Possible productivity enhancement / rate changes simplified / possible reprogram rather than mtr change
7 Outage management benefits (momentary checking for PG&E)
8 Better meter functionality / equipment modernization
9 Remote service connect / disconnect
10 Meter accuracy
11 System planning design efficiency

Customer Service Benefits
12 Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”
13 Early detection of meter failures
14 May provide additional opportunity to inspect panel, reattachment of unsecured mtr boxes, ID any unsafe conditions
15 Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing
16 Customer energy profiles for EE / DR targeting (marketing)
17 Customer rate choice / new rate options
18 Customized billing date
19 Energy Information
20 Enhanced billing
21 Load Survey
22 On-line bill presentment with hourly data / more timely and accurate information about electricity / info access
23 Lower customer bills
24 Value to customers of more timely & accurate bills

Demand Response Benefits
25 Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions
26 System reliability adder (capacity buffer)
27 Dynamic fuel switching / Dynamic integration of conventional and distributed supplies
28 Avoided / deferred transmission and distribution (T&D) additions / upgrade costs

Management and Other Benefits
29 Reduced equip and equip maint costs (software maint & system support, handheld reading devices, uniforms, etc.)
30 Reduced misc. support expenses (including office equipment and supplies)
31 Reduced battery replacement / calendar resets / meter programming
32 Reduced meter inventories / inventory management expenses due to expanded uniformity
33 Summary billing cash flow benefits (existing customers)
34 Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes
35 Possible new rev source / new business ventures / new products & srvs / web based interval & power-quality data
36 May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes
37 Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs
38 Potential for Federal investment tax credits

Appendix 3

Table 1 ***Energy (LBMP) Price Forecast***							
NYISO ZONE ($/MWH in 2008 $)							
	A-E	F	G-I	J	K	NYS	A-I
Year							
2008	$60.80	$71.28	$77.52	$81.08	$88.35	$75.69	$66.38
2009	$63.32	$71.53	$80.59	$83.15	$87.69	$77.85	$69.22
2010	$62.01	$69.93	$79.25	$81.54	$85.25	$76.22	$67.87
2011	$60.78	$68.43	$78.00	$80.03	$82.96	$74.69	$66.61
2012	$59.58	$66.97	$76.78	$78.56	$80.73	$73.19	$65.37
2013	$59.44	$66.80	$76.18	$78.26	$80.51	$72.93	$65.14
2014	$59.30	$66.63	$75.59	$77.97	$80.29	$72.67	$64.91
2015	$59.17	$66.46	$75.00	$77.68	$80.08	$72.41	$64.68
2016	$59.31	$66.63	$75.19	$77.87	$80.27	$72.58	$64.84
2017	$59.46	$66.79	$75.37	$78.06	$80.47	$72.76	$65.00
2018	$59.60	$66.95	$75.56	$78.26	$80.67	$72.94	$65.16
2019	$59.75	$67.12	$75.74	$78.45	$80.86	$73.12	$65.32
2020	$59.90	$67.28	$75.93	$78.64	$81.06	$73.30	$65.48
2021	$60.04	$67.45	$76.11	$78.83	$81.26	$73.48	$65.64
2022	$60.19	$67.61	$76.30	$79.03	$81.46	$73.66	$65.80
2023	$60.34	$67.78	$76.49	$79.22	$81.66	$73.84	$65.96
2024	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
2025	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
2026	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
2027	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
2028	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
2029	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
2030	$60.49	$67.95	$76.68	$79.42	$81.86	$74.02	$66.12
Notes							
A-E, G-I, A-I, NYS weighted averages using energy requirements							
Above estimates do not include distribution line losses. Add an average 7.2% estimate (i.e. divided above costs by 0.928)							

Table 2
Marginal Capacity Price Forecast

	MARGINAL GENERATION		MARGINAL DISTRIBUTION	
	CAPACITY COSTS		CAPACITY COSTS	
	($/KW-Year in 2008 $)		($/KW-Year in 2008 $)	
Year	Upstate	NYC	Upstate	NYC
2008	$31.13	$55.19	$33.48	$100.00
2009	$38.65	$55.51		
2010	$45.77	$120.22		(constant in 2008 $)
2011	$52.39	$119.74		
2012	$58.61	$119.22		
2013	$64.47	$125.08		
2014	$69.98	$121.04		
2015	$75.16	$113.36		
2016	$80.04	$122.29		
2017	$84.62	$136.08		
2018	$88.93	$137.15		
2019	$92.98	$138.11		
2020	$96.78	$138.98		
2021	$100.35	$139.76		
2022	$100.35	$139.76		
2023	$100.35	$139.76		
2024	$100.35	$139.76		
2025	$100.35	$139.76		
2026	$100.35	$139.76		
2027	$100.35	$139.76		
2028	$100.35	$139.76		
2029	$100.35	$139.76		
2030	$100.35	$139.76		

Notes

Marginal Generation Capacity Costs include reserve margin and demand curve purchase requirements.

Thus, these are a forecast of annual savings in generation marginal capacity costs due to 1 kW reduction in load at the time of peak load.

Marginal transmission costs included in LBMPs.

Above estimates do not include distribution line losses. Add an average 7.2% estimate (i.e. divided above costs by 0.928

Appendix 3

Table 3 ***Natural Gas Price Forecast*** Based on the 10/6/08 ICF/NYSERDA Interim Forecast ($/MMBtu in 2008 $)			
Year	Henry Hub	Upstate NY	Downstate NY
2008	$9.45	$10.38	$10.92
2009	$7.67	$8.60	$9.14
2010	$7.45	$8.38	$8.92
2011	$7.24	$8.17	$8.71
2012	$7.04	$7.97	$8.51
2013	$7.04	$7.97	$8.51
2014	$7.04	$7.97	$8.51
2015	$7.04	$7.97	$8.51
2016	$7.11	$8.04	$8.58
2017	$7.18	$8.11	$8.65
2018	$7.25	$8.18	$8.72
2019	$7.25	$8.18	$8.72
2020	$7.25	$8.18	$8.72
2021	$7.25	$8.18	$8.72
2022	$7.25	$8.18	$8.72
2023	$7.25	$8.18	$8.72
2024	$7.25	$8.18	$8.72
2025	$7.25	$8.18	$8.72
2026	$7.25	$8.18	$8.72
2027	$7.25	$8.18	$8.72
2028	$7.25	$8.18	$8.72
2029	$7.25	$8.18	$8.72
2030	$7.25	$8.18	$8.72

Appendix 4

Efficiency Program Selection Criteria[1]

Screening Metrics: Minimum to be Filed

For each program:

1. **Total Resource Cost Test's Benefit-Cost Ratio**:

   The benefits calculated in the TRC Test are the avoided supply costs, including the reduction in costs of electric energy, generation, transmission, and distribution capacity, and natural gas, valued at marginal cost for the periods when there is a load reduction. The program costs are those paid by the program administrator and participants plus the increase in supply costs for any period when load is increased. To the extent practical, the filing should include the total cost and associated energy and demand savings for each measure contained within the program.

2. **Electric Rate Impact**:

   This metric provides the percentage increase in current delivery and overall rates associated with a particular program. The results should be provided on a levelized basis assuming a) the program continues to expand and extends through 2015 and b) the program functions only for as long as proposed by its sponsor. The rate impact effect of avoided transmission and distribution costs should be clearly presented. Thus, rate impacts should be presented both with, and without, avoided transmission and distribution costs.

3. **Electric Rate Impact per MWh Saved**:

   This metric provides the levelized rate impact per MWh saved, stated separately for delivery and overall rates, assuming a) the program continues to expand and extends through 2015 and b) the program functions only for as long as proposed by its sponsor.

4. **Electric Rate Impact per MW Saved**:

   Same as 3 above, except it is per MW saved at the time of system peak.

5. **MWh Saved in 2015**:

   This metric reflects the amount of MWhs saved in 2015 assuming a) the program continues to expand and extends through 2015 and b) the program functions only for as long as proposed by its sponsor.

1 Only the highlighted topics will be given weight and attention in Staff's review of the AMI filings.

6. **<u>MW of Coincident NYISO Peak Saved in 2015</u>**:

This metric reflects savings in MWs at time of system peak. This metric should reflect MWs assuming a) the program continues to expand and extends through 2015 and b) the program functions only for as long as proposed by its sponsor.

7. **<u>Peak Coincidence Factor of MWh Saved in 2015</u>**:

This metric is a measure of the extent to which the MWhs saved for each program are concentrated at the time of system peak. The peak coincidence factor is a measure of the extent to which the MWhs saved are concentrated in peak hours versus distributed evenly across the 8760 hours a year. Peak coincidence factor is defined as:

$$\text{Peak coincidence factor} = \frac{[\text{annual MWh saved}]}{[(\text{MW saved on peak}) \times (8760 \text{ hours})]}$$

8. **<u>Total Resource Cost Test's Benefit-Cost Ratio, with Carbon Externality Added, Assuming a Carbon Value of $15 per ton (TRC plus C)</u>:**

This metric makes a single change to the Total Resource Cost Test by adding on an estimate of the benefit of carbon reduction. Parties are free to provide additional quantifications based on alternative $/ton values.

9. **<u>Number of Participants as a Percentage of the Number of Customers in the Class as of 2015</u>.**

10. **<u>Gas Rate Impact</u>**:

This metric provides the percentage increase in current delivery and overall rates associated with a particular program. The results should be provided on a levelized basis through 2015 and on the basis of the impact of the first full calendar of implementation.

11. **<u>Gas Rate Impact per MBTU Saved, Levelized Over the Years Through 2015</u>**:

This metric provides the levelized rate impact per MBTU saved over the years through 2015 separately for delivery and overall rates.

<u>For the suite of programs as a whole:</u>

1. **<u>Electric Rate Impact as of Year 2015</u>**:

This metric reflects the percentage increase in rates caused by the suite of programs, assuming that it remains in place through 2015 and assuming, hypothetically, that it is upsized to constitute the Commission's entire jurisdictional share of the 15 x 15 goal.

1 Only the highlighted topics will be given weight and attention in Staff's review of the AMI filings.

2. **Gas Rate Impact as of the Year 2015**:

Same as (1) above.

1 Only the highlighted topics will be given weight and attention in Staff's review of the AMI filings.