STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on February 12, 2009

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.
James L. Larocca

CASE 09-M-0074 – In the Matter of Advanced Metering Infrastructure.[1]

ORDER ADOPTING MINIMUM FUNCTIONAL REQUIREMENTS FOR ADVANCED METERING INFRASTRUCTURE SYSTEMS AND INITIATING AN INQUIRY INTO BENEFIT-COST METHODOLOGIES

(Issued and Effective February 13, 2009)

BY THE COMMISSION:

INTRODUCTION

The Commission previously directed electric utilities to file comprehensive plans for development and deployment, to the extent feasible and cost effective, of advanced metering infrastructure (AMI) systems for the benefit of all customers. Gas utilities were simultaneously directed to assess the feasibility of developing, offering, and installing AMI systems for large volume gas customers. Utilities filed their AMI plans during the first quarter of 2007. During the course of their review, it was determined that consistent criteria are needed to allow for the proper evaluation of the various AMI plans submitted. Specifically, the various plans should be measured against a clear and

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[1] This case continues, supersedes and replaces proceedings previously held in the following cases: Case 00-E-0165, In the Matter of Competitive Metering, Case 02-M-0514 – Proceeding on Motion of the Commission to Investigate Competitive Metering for Gas Service, and Case 94-E-0952 – In the Matter of Competitive Opportunities Regarding Electric Service.

comprehensive understanding of the minimum functions AMI systems are intended to achieve. To that end, we solicited comments and held a technical conference to gather information in support of guidelines that can be used in the development of AMI plans and in the evaluation of those AMI plans to ensure that the features and functions contained therein are appropriate, given our goals, the state of the art in metering and communications technology, and the cost of the desired features. This order is a culmination of that information gathering effort and, thereby, establishes the minimum functional requirements for AMI systems.

In addition to establishing minimum functional requirements for AMI systems, we are initiating a process for the development of a generic approach to the benefit-cost analysis of AMI. In making decisions about AMI deployment, it is crucial to have a well-developed benefit-cost analysis. The processes initiated by this order should provide the parties with an opportunity to discuss and examine issues associated with benefit-cost analysis, leading to a future decision by us in which a proper benefit-cost analysis methodology can be established.

BACKGROUND

On October 10, 2007, we requested comments from parties concerning a draft list of AMI features and functions. Specifically, parties were asked to address the following considerations:

- whether the list is sufficiently comprehensive, or whether additional features or functions should be specified;
- whether the list includes items that should not become part of a Commission standard;
- whether the items included on the list are accurately and/or sufficiently defined; and, if not, how to improve the definition; and
- any other matters related to such an AMI standard not otherwise addressed by the above questions.

The draft list of AMI features on which we sought comment was composed of the following items:

a) ANSI compliant (must meet all ANSI standards).
b) Bi-directional registration (supports net metering).

c) Visual read capability for cumulative usage.
d) Ability to provide time-stamped interval data, at hourly or shorter time intervals.
e) On-board meter memory capable of storing at least 60 days of readings.
f) Direct, real-time (defined as a time lag of five minutes or less) remote read-only access for customers and/or competitive providers to meter data.
g) Capability to remotely read meters on-demand.
h) Utilizes open standards-based communication protocols and platforms, e.g., broadband, PLC, internet, XML, MV-90, Zigbee, DNP3, etc.
i) Two-way communications capability, including ability to remotely upgrade meter firmware.
j) Ability to send signals to customer equipment to trigger demand response functions, and/or connect with a home area network (HAN) to provide direct or customer-activated load control.
k) Positive notification of outage/restoration.
l) Self diagnostics, including tamper flagging capability.
m) Upgrade capability.

PUBLIC NOTICE AND COMMENT

Notice regarding our proposed requirements was published in the State Register on October 24, 2007. The minimum comment period expired on December 10, 2007. Comments were filed by Central Hudson Gas and Electric Corporation (Central Hudson); Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc., filing jointly (Con Edison/O&R); Constellation New Energy Group, Inc.; Current Group, LLC; Distribution Control Systems, Inc. and Hexagram, Inc., filing jointly (DCS/Hexagram); Elster Integrated Solutions; EnerNOC, Inc.; (EnerNOC); Energy Curtailment Specialists, Inc.; Itron, Inc.; Multiple Intervenors; National Fuel Gas Distribution Corporation; National Grid, USA Service Company, Inc.; New York State Electric and Gas Corporation, and Rochester Gas and Electric Corporation, filing jointly (NYSEG/RG&E); New York State Energy Research and Development Authority (NYSERDA); New York State Independent System Operator (NYISO), Retail Energy Supply Association, and Sensus Metering Systems, Inc.

Several parties' comments requested that further process steps be taken, such as convening a technical conference, to help identify the functions that should be included in AMI systems. Staff convened a technical conference, the purpose of which was to aid in Staff's efforts to develop minimum functional requirements for utility AMI systems, by increasing its knowledge and understanding of this rapidly evolving and technically complex subject. The technical conference was held on April 14-15, 2008, in Albany.[2]

Parties offered responses to the general questions posed above, as well as addressing whether a particular function was essential to AMI functionality. The technical conference also provided invaluable guidance and greatly informed our decisions on these matters. We express our appreciation to all of the conferees for sharing their time and valuable expertise with us. Information gleaned from the technical conference as well as the parties' written comments on general matters and on each of the proposed functions is discussed below.

Many parties argued that the Commission's efforts to establish minimum functionality were misguided. Some believed it was premature and that the Commission should focus on piloting a variety of technologies at this stage. Some argued that establishing minimum functionality implies a "one-size-fits-all" approach that is inconsistent with the realities of the market and may result in AMI systems designed with capabilities that only a few customers will use, or that few vendors will be able to provide. These parties thought that it would be preferable to continue the Commission's previous policy of broadly defining AMI requirements, and allowing utilities maximum latitude in determining how AMI systems should be equipped.

Several parties suggested that establishing minimum functional requirements was a complex undertaking that required considerable time and effort. Pointing to proceedings that took months or years to develop comparable requirements in other states, such as California, Texas and Maryland, several parties proposed that we hold technical conferences and/or other collaborative efforts to develop and refine AMI functional requirements. The proceedings in California, Texas and Maryland have already produced standards for AMI in those states. Much preliminary work was already done, and the draft requirements Staff issued for comment were based on the standards

[2] Transcripts of the conference proceedings are available on the Commission's website at http://www.dps.state.ny.us/AMI.htm.

adopted in those states. As suggested by many parties, we elected to authorize the technical conference in order to develop a better understanding of the state of technological development of AMI.

DISCUSSION

The development of minimum functional requirements of necessity reflects the state of the available technology at the time the requirements are developed. We have endeavored to ensure that the requirements we adopt here are technically and economically feasible in the marketplace; however, AMI systems are evolving at a rapid pace and will likely continue to evolve. At any point that it is decided to specify minimum requirements, those requirements could be subject to change. If the functional requirements are regarded as a living document, that can be revised and updated as the state of metering technology progresses, we can proceed with establishing requirements now and revisit those requirements, including the holding of further proceedings as circumstances require.

The minimum functional requirements we establish here are guidelines for the utilities to use in developing their AMI plans. The Commission's previous policy of broadly defining AMI requirements produced the AMI proposals presently before us, and that experience led us to conclude that there should be greater specificity to the requirements. Because AMI technologies will undoubtedly continue to evolve, we expect to allow utilities flexibility in meeting AMI minimum functional requirements. Reference to the minimum functional requirements will better enable the utilities to determine whether they have addressed the goals we have in mind; however, if a utility believes that it can achieve the same result through a different route, or if it believes that adherence to a particular requirement would not be cost-effective in its particular circumstances, it can explain its reasoning in its AMI plan filing and seek waiver of the applicable functional requirement. Furthermore, setting minimum functional requirements does not preclude a utility from proposing additional functionality that provides improvements in customer service, system operations and/or the overall cost effectiveness of its proposal. For all of these reasons, the proposals to abandon these efforts, or to institute a more lengthy inquiry, are rejected.

AMI Meter vs. System Requirements

Concerning many of the proposed requirements, parties sought clarity or alternatively expressed their underlying assumptions with regard to whether the requirement applied specifically to the AMI meter, or to the AMI system. AMI systems generally consist of three components: meters, a meter data management database, and a two-way communications network that links the meters and the database together. For the most part, the desired functionality described in the various requirements can reside in any part of the AMI system. There are some exceptions, e.g., requirement (e) for on-board meter memory is designed to overcome potential failures elsewhere in the system, and such requirements are specified where appropriate. Otherwise, the minimum functions should be deemed system requirements.

Electric vs. Gas Systems

Some parties stated that certain of the proposed requirements had no applicability to gas service, and/or expressed their assumption that a particular requirement was limited to electric service. AMI systems proposed by the utilities in New York, as well as those proposed or in use elsewhere, are generally designed to provide greater functionality for electric service, although automated meter reading (AMR) is often included for gas service.[3] The functional requirements described herein should therefore be understood as applicable to electric AMI systems, unless specifically stated to apply to gas AMI systems as well. We nevertheless encourage the utilities to examine the potential for improving the cost-effectiveness of their AMI system proposals by incorporating gas meter reading or other gas service enhancements. This potential

[3] Virtually all of the state's largest gas customers – those with peak usage of 5,000 DTh or more, are already provided with meters capable of measuring daily usage.

could be explored by combination utilities with respect to their own gas systems, as well as in the areas where the service territories of electric, gas and/or water utilities overlap.

(a) ANSI Compliant (Must Meet All ANSI Standards)

It is widely understood that standardization enables interoperability among the devices manufactured by different suppliers, increasing competition and lowering costs. In general, parties agreed with the requirement that AMI systems should comply with American National Standards Institute (ANSI) standards, and some parties noted that such a requirement is already part of the Commission's regulations.[4] Some parties noted that the requirement should be restricted to ANSI standards related to metering; others expressed the view that compliance with other standards also should also be required, e.g., FCC regulations pertaining to communications media. Some speakers at the technical conference noted that ANSI standards define how to measure and record meter data, but ANSI standards for demand response, load control and other advanced functions are still under development.[5] We adopt the requirement as follows:

> AMI systems must be compliant with all applicable ANSI standards, Commission regulations and federal standards, such as FCC regulations.

(b) Bi-Directional Registration (Supports Net Metering)

In general, parties also agreed with this requirement, though some parties again noted that such a requirement is already specified by statute and the Commission's regulations.[6] Some parties suggested that the critical component of this requirement was "supports net metering," and that "bi-directional registration" was a means to that end, but not necessarily the only means. Representatives of meter manufacturers at the technical conference indicated that net metering was fast becoming a standard feature.

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[4] See 16 NYCRR Part 93.

[5] ANSI C12.22 is expected to be released in February 2008. This standard allows the transport of meter data over networked connections.

[6] See PSL §§66-j, 66-l.

The federal Emergency Economic Stabilization Act of 2008 defines a "smart meter" (for tax depreciation purposes) as any time based meter and related communication equipment that (i) measures and records electricity usage data on a time-differentiated basis in at least 24 separate time segments per day, (ii) provides for the exchange of information between supplier or provider and the customer's electric meter in support of time-based rates or other forms of demand response, (iii) provides data to such supplier or provider so that the supplier or provider can provide energy usage information to customers electronically, and (iv) provides net metering.[7] It appears that this function is widely recognized as part of minimum AMI requirements. We adopt the requirement as follows:

> AMI systems must provide net metering.

<u>(c) Visual Read Capability For Cumulative Usage</u>

Parties' comments support a requirement for customers to have the ability to obtain consumption information. Many parties noted that other technologies and options – e.g., in-home displays or web presentment of usage data – may make a requirement for a visual readout at the meter obsolete; however, parties agree that AMI meters should not provide any less ability for customers to obtain meter readings than exists with conventional meters. Given these considerations, we adopt the requirement as follows:

> AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with the auxiliary device if it is the only means of a visual read of consumption data.

<u>(d) Ability To Provide Time-Stamped Interval Data, At Hourly Or Shorter Time Intervals</u>

Parties generally agreed that AMI meters must be capable of producing hourly usage data, although some parties believed that capability for shorter intervals should also be required, (e.g., five or 15 minute intervals), and some parties thought the

[7] Emergency Economic Stabilization Act, § 306.

requirement was ill-defined and left some ambiguity as to whether the proposed requirement mandated shorter intervals.

While some customers may have uses for five or 15-minute interval usage data, we are not persuaded that intervals of less than an hour should be part of a minimum requirement. There are no technical issues with providing hourly interval data and having the capability to provide hourly interval data is a basic requirement of the federal definition. Moreover, as further discussed below, we will require that AMI systems have the ability to remotely program meters, which should include the ability to program shorter intervals. We adopt the requirement as follows:

> AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.

<u>(e) On-Board Meter Memory Capable Of Storing At Least 60 Days Of Readings</u>

Many commenting parties thought the 60 day requirement was excessive. Some commented that, given the multiplicity of configurations and the range of frequencies of data retrieval that AMI system designs might include, requiring any particular period was too specific, and suggested instead restating the requirement to capture the need to preserve data at the meter in case of malfunctions at other points downstream of the meter in the AMI system. On the other hand, meter suppliers at the technical conference generally indicated that memory in meters is relatively inexpensive and that providing adequate memory to store data should not present a cost concern.

The proper functioning of AMI systems will rely on the interaction of their three major components. Usage data is produced by the meter, transmitted over the communications network, and stored in the meter data management system until it is retrieved to prepare the customer's bill or for other purposes. A certain amount of usage data storage capability should be designed into the meter itself (in that regard, this particular requirement refers to the meter itself, not the system) so that in the event of a failure of the communications network or the meter data management system, customer usage data will not be lost. With these considerations in mind, we adopt the requirement as follows:

> AMI meters must have sufficient on-board meter memory capability to ensure meter data is not lost in the event of an AMI system failure and that billing data for the previous and current billing period are stored on the meter.

<u>(f) Direct, Real-Time (Defined As A Time Lag Of Five Minutes Or Less) Remote Read-Only Access For Customers And/Or Competitive Providers To Meter Data.</u>

Most parties believed that customers should be empowered with real-time access to their own usage data, though some demand response providers warned against utilities placing undue restrictions on data access, and the utilities expressed concern that providing direct access to customers and third parties raised meter security issues, excess cost issues, or both.

Meter vendors at the technical conference evidently agree that low-cost technologies exist for providing a streaming data signal from the meter to provide customers with secure real time access to their electric meter data. The streaming signal generally is sent by a low power radio frequency transmitter and received by a device that displays the data in real time. It appears that sixty second and faster refresh rates are easily achieved.

As further explained below, we intend that all meter data information be exchanged among parties in open, non-proprietary data formats. We therefore adopt this requirement as follows:

> AMI systems must have the ability to provide customers direct, real-time access to electric meter data. The data access must be provided in an open non proprietary format.

<u>(g) Capability To Remotely Read Meters On-Demand</u>

No party opposed this requirement. We adopt the requirement as follows:

> AMI systems must have the ability to remotely read meters on-demand.

(h) Utilizes Open Standards-Based Communication Protocols And Platforms, e.g., Broadband, PLC, Internet, XML, MV-90, Zigbee, DNP3, Etc.

Parties offered a broad range of comments on this requirement. Some noted that proprietary protocols and platforms may be more-cost effective in certain situations, and in other situations (e.g., within LAN-based networks), may be the only means available. Other parties variously pointed out that the examples given in the draft requirement were not interchangeable, were not standards-based, and/or were not finalized. One party noted that broadband and PLC are not communications protocols.

In the opinion of many, including many of the technical conference speakers, the situation regarding meter communications protocols remains somewhat unsettled. Although the metering industry was until recently dominated by proprietary systems, this is clearly changing, and technical conference speakers discussed many important efforts to develop best practices and *de facto* standards. For example, some U.S. utilities, vendors, consultants, and others are working together through the Utility Communications Architecture International Users Group and its Utility AMI working group and task forces to develop interoperability requirements that would allow plug-and-play interfacing among the components of AMI systems.

Recognizing a need for standards that would enable interoperability, the U.S. Congress in the Energy Independence and Securities Act of 2007 directed the National Institute of Standards and Technology to establish "protocols and model standards for information management to achieve interoperability of smart grid devices and systems."[8] In the interim, numerous standards developed for other communications areas – such as broadband, PLC, cellular, paging, microwave, Internet, etc. -- have been adapted for use in metering.

Facilitating interoperability lowers costs and increases competition among suppliers; however, many areas of metering are not covered by standards. Although

[8] Energy Independence and Securities Act of 2007, Pub. L. 110-140, §§1303, 1305, 121 Stat. 1787 (2007).

serious efforts are underway, formal standards often take years to build consensus. Industry best practices like Utility AMI may bear more short-term fruit – but provide less surety for the same reason. This only means that some portions of AMI systems will inevitably include proprietary designs. Until formal standards further develop, utilities can continue to use, adopt, further develop, contribute to and procure to key industry level standards.

DCS/Hexagram, in written comments, suggested that the concern should not be to eliminate all proprietary systems; rather, the requirement should be the ability to interface with the AMI system via an open standard methodology. Use of a recognized open protocol for the data to be exchanged at the interfaces of the AMI meter communications system will permit the interoperability we seek to achieve.

Utilization of open, standards-based communication protocols and the availability of commercial broadband communications solutions also allow for the possibility that the underlying AMI communications system need not rely on the functional limitations of the meter or the electric network as a required element for data transport. Utilities are encouraged to investigate opportunities to leverage existing communications networks such as cable and telephone networks for use in AMI systems.

Open standards facilitate the maximization of customer control and will further encourage innovation in devices in the home area network, allow greater choice in the devices the can interface with the AMI system, and greater flexibility for the future configurations of the system. We adopt the requirement as follows:

> At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.

(i) Two-Way Communications Capability, Including Ability To Remotely Upgrade Meter Firmware

Most parties agreed with this requirement in their written comments, although Central Hudson's written comments cautioned that the terminology suffers from a lack of specificity, particularly in what is included in "firmware." EnerNOC, a demand response provider, commented that the requirement should be modified to include the ability of other authorized agents to communicate with the meter.

At the technical conference, many speakers sought to distinguish between two separate capabilities included in this requirement: two-way communication and remote upgrade capability. Two-way communication includes the ability to reliably send data both to and from the customer's meter in support of time-based rates or other forms of demand response. Remote upgrade involves the ability to remotely reconfigure the meter, update security and other meter settings, and download new firmware into the meter. As we previously discussed, remote upgrade capability should include the ability to remotely program the meter to provide shorter billing intervals than one hour.

Two way communication is facilitated by open communications protocols as discussed above. We agree that support of demand response must provide for the exchange of information between other energy services providers and the customer's electric meter. We are further aware that some New York utilities have invested in one-way communications technologies associated with AMR installations. These utilities have to assess whether conversion to two-way capability is cost-justified.

Remote download capability requires a highly secure channel, and need not be offered to third parties as EnerNOC suggests. Planners must also consider the need for sufficient bandwidth to support download capability. One technical conference speaker referred to the case of a European utility that designed its system for remote upgrade capability, but later found that implementing a new rate structure took nine months to download to all of the meters on its system.

We decline to specify a maximum time requirement associated with meter upgrades, but each utility should be clear as to what level of download capability is supported by its proposed design. With the caveat that utilities in subsequent AMI proposals will need to explain how their proposals comport with this requirement, we adopt the requirement as follows:

> AMI systems must have two-way communications capability, including ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.

(j) Ability To Send Signals To Customer Equipment To Trigger Demand Response Functions, And/Or Connect With A Home Area Network (HAN) To Provide Direct Or Customer-Activated Load Control

Our interest in AMI primarily stems from its ability to induce customer behavioral changes that produce demand reductions. Many parties see enormous potential for demand reduction in the automation of home appliances, and AMI as an important, perhaps critical communications gateway to devices at the customer's site. This capability is what enables in-home displays of customer usage discussed above, and permits applications such as remote load control, monitoring and control of distributed generation and integration with building management systems.

Some parties cautioned that HAN and similar home appliance control systems are nascent technologies. As with most such cutting edge technologies, there are several competing designs, and there is further a lack of integration of HANs with AMI systems. Moreover, appliances, to date, are generally not HAN-enabled, and HAN-integrated programmable communicating thermostats or in-home displays with HAN communications modules have only recently been introduced. The embedding of HAN controllers in utility meters, therefore exacerbates already existing and substantial privacy, security, communication, competitive, and hardware obsolescence issues raised by AMI systems.

Finally, we are concerned about allowing the utility, as a regulated monopoly, to gain an advantage in what could be an otherwise competitive home automation market. Broad adoption of interoperability standards, one based on the 2008 HAN System Requirements Specification, for example, could lessen these concerns.[9]

Notwithstanding that uncertainty, it would be unfortunate if HANs are developed by home builders and appliance manufacturers to send and receive signals

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[9] The Open HAN task force of the Utility AMI Working Group released its 2008 HAN System Requirements Specification, which is designed to facilitate standards and technology development to enable dissimilar HAN protocols to interface and work interoperably.

from AMI systems, but New York's AMI systems were not designed to take advantage of this capability. In order to maximize demand response benefits, AMI systems must provide a portal that can send signals to customer equipment that trigger demand response functions, and our previous experience with reliance on competitive forces to stimulate innovation in metering were disappointing. Utilities must provide meter data in open, non-proprietary formats, and are encouraged to thoroughly explore the prospects for supporting competitive provision of automated and customer-activated load control. Therefore, we adopt the requirement as follows:

> AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network (HAN) to provide direct or customer-activated load control.

(k) Positive Notification Of Outage/Restoration

Many parties believe the proposed requirement is too restrictive. Some noted that "positive" notification would appear to eliminate power line carrier as a communications medium. Others suggested that outage or restoration advice need not be provided on an individual meter level, as this could overload (or alternatively, require overbuilding) of certain systems, and/or that some AMI systems may have other means of providing outage management information.

Our expectation is that AMI systems can enhance the capability to detect and report power outages and restorations, leading to faster responses to and recovery from outages. This requirement is intended to ensure that the full benefit of such enhancement is captured. We adopt the requirement as follows:

> AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.

(l) Self Diagnostics, Including Tamper Flagging Capability

Security considerations must be paramount in designing AMI systems. Any implementation of AMI must be designed to minimize the risks to the accuracy and confidentiality of customers' metered usage data. AMI systems have characteristics that impact what security solutions can be implemented. Smart meters and communications networks can themselves increase the vulnerability of the system to cyber attacks. Implementing AMI increases cyber security risks by increasing the number of potential access points into the utility's data network. This risk is also increased by the provisioning of two-way communications capabilities with AMI end-point devices. In addition, AMI systems are still very new, with their functionality still being worked out and with many different functional requirements and technological solutions being tested. Given the diversity and novelty of the entire AMI system concept, the security challenges are significant.

Solutions to the security threats must take into account many different issues, situations, and constraints. Data encryption alone cannot cover all security threats. Access controls, e.g., passwords and digital certificates help, but still do not resolve all security threats. Another essential element is a forensics ability needed to detect intrusions and assess damage.

Security must be built in from the beginning to be truly effective, but often it is the lowest consideration as all of the other competing demands are being pursued. Very little effort to date has been focused on the cyber security of AMI systems. A Utility AMI Security Task Force has been working intensively since April 2008, but with much work yet to do before producing technical specifications that may be used by utilities to assess and procure security related functionality.

We have only begun to scratch the surface of addressing security issues, and we recognize that security functionality requirements will need to be revisited, perhaps frequently. With that in mind, we adopt the requirement as follows:

> AMI systems must have the following security capabilities: (i) Identification - uniquely identify all authorized users of the system to support individual accountability; (ii) Authentication – authenticate all users prior to initially allowing access; (iii) Access Control - assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated; (iv) Integrity – prevent unauthorized modification of data, and provide detection and notification of unauthorized actions; (v) Confidentiality - secure data stored, processed and transmitted by the system from unauthorized entities; (vi) Non-repudiation - provide proof of transmission or reception of a communication between entities; (vii) Availability -

ensure that information stored, processed and transmitted by the system is available and accessible when required; (viii) Audit - provide an audit log for investigating any security-related event; and (ix) Security Administration – provide tools for managing all of the above tasks by a designated security administrator.

(m) Upgrade Capability

Some parties were concerned that this requirement lacked clarity, particularly in how it was distinct from requirement (i) above. Some parties believed that in light of requirement (i), this requirement was redundant and could be omitted.

Physical components of the meter are not susceptible to remote reprogramming. For example, if a utility equips a meter to function on a RF network, and thereafter elects to convert to a broadband communications, such meters would become stranded assets unless the utility is able to make physical changes to meter components that allow it to function on a different communications medium. This could be accomplished by modular designs that allow various components to be easily exchanged, or by other designs that call for physical components to be upgraded periodically.

While this is a valuable capability, it does not directly affect the meter functionality that can be offered to the customer, and we are persuaded by those parties who argued that the value of upgradability should be assessed by each utility in consideration of its overall system design. Accordingly, this functional requirement is withdrawn.

Additional Functions and Features

Parties listed several items that were not part of the proposed list. A few referenced AMI definitions developed by FERC or other jurisdictions, and/or offered AMI definitions of their own design. Some proposed the inclusion of specific functions, such as power quality measurements. Other parties did not list specific features, but proposed procedural requirements such as coordinating AMI requirements with NYISO requirements for demand response programs.

As previously discussed, the intent of developing this list of AMI features and functions is to establish minimum functional requirements for AMI. Other features and functions can be valuable and useful, and the utilities may include other functions in their AMI Plan proposals; however, we will not further extend our list of minimum requirements at this time. Since eligibility for participation in NYISO demand response programs may be limited to certain customers, and may change over time, we do not believe it would be appropriate to link such requirements to the minimum requirements for AMI systems.

Smart Grid

The term "Smart Grid" generally refers to a concept that will allow significantly more sophisticated and efficient operation of power systems. It includes advanced technology and communication systems, involving facilities from the generator, transmission and distribution systems, down to the end-use customer. AMI is a component of Smart Grid. Smart Grid is very much an evolving entity, as many of the technologies necessary to meet the objectives of a Smart Grid are still under development.

Ultimately, implementation of the Smart Grid could hold great promise for improving system efficiency and reliability; however, it is a concept that is both larger than AMI and less well defined. What is clear is that an AMI communications infrastructure that provides instant two-way communication to any part of the grid can be a key enabling technology that can help achieve the Smart Grid's objectives.

The utilities must consider how their deployments of AMI can be integrated into other Smart Grid capabilities, so that the communications backbone and data management systems can be leveraged to provide both AMI and Smart Grid capabilities. Further, it is essential that deployment of communication facilities for AMI does not result in stranded facilities that are not capable of being expanded for broader Smart Grid applications. Therefore, AMI systems must be designed to meet future requirements of the Smart Grid, and particular must contain communications systems that are scalable and expandable to accommodate sensors in multiple locations throughout the grid.

Remote Disconnection/Prepayment

Many parties believe that AMI systems should be required to be capable of remote disconnection/reconnection of service. As we discussed in our Central Hudson and Con Edison/Orange and Rockland orders, 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.

The ability to reconnect the meter can certainly produce value for customers, and many customers might benefit from the ability to have service connected and disconnected remotely for other reasons than non-payment. This feature has other uses, such as for emergency load shedding. Moreover, it appears that the remote disconnection switch has become a nearly universal feature on new digital meters.

We have no doubt that many utilities will find that remote disconnection/reconnection capability will provide opportunities for significant labor savings, and will be inclined to include this capability in their AMI plan proposals in any event. We therefore conclude that there is no reason to include it as a minimum functional requirement.

A few parties also proposed that prepayment capability be included. In contrast to remote disconnection; however, there is no prospective use of prepayment meters that does not conflict with HEFPA. Under the PSL and our regulations, customers have the right to a reasonable billing interval, and written notice, among other things, before service can be terminated for nonpayment. There is no place for prepayment among the services to be offered to residential customers in New York State.

Benefit-Cost Analysis

In making decisions about AMI deployment, it is crucial to have a well-developed benefit-cost analysis. More than half of the costs of installing AMI can be offset by a reduction in traditional utility costs of operations or improved services, such as avoided meter-reading costs, faster outage detection and improved customer service. A projection of benefits from the demand response enabled by the AMI system must be included to bridge any benefit-cost gap based on what is recoverable from AMI-operational savings alone.

Estimations of demand response savings from AMI-enabled dynamic pricing programs will in turn depend on estimations of the number of participants who sign up for time-differentiated rates, and their response to critical peak prices, i.e., on their price elasticity of demand. Participation rates for "opt-in" dynamic pricing programs may be particularly difficult to estimate in advance, as they will likely be highly dependent on program designs, the rates offered, and the success of marketing efforts.

As we noted in an earlier order, the benefit-cost methodologies that have been filed were not modeled on the kinds of analytical procedures that are used in New York to evaluate energy efficiency programs.[10] Furthermore, as has been found in other states such as California that have already made AMI deployment decisions, several components of an AMI benefit-cost analysis are important determinants of the results, yet can be controversial, and/or need to at least be reasonably consistent from utility to utility. These include, for example, AMI meter life and the discount rate used to project the net present value of future years' benefits.

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 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

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[10] Case 00-E-0165, et al., In the matter of Competitive Metering, Order requiring filing of Supplemental Plan, (Issued December 19, 2007).

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.

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.

We have already issued orders directing Con Edison and O&R (filing jointly) and Central Hudson to file revisions to their AMI pilots, based on the functional requirements we adopt here. In our earlier orders, we required the filing of revised benefit-cost analyses as part of the revised filing. That requirement is lifted in light of our decision herein to begin a process to examine benefit-cost methodologies.

NYSEG and RG&E also jointly filed an AMI Plan. As the AMI minimum functional requirements we adopt here will guide our evaluation of all AMI Plans, NYSEG/RG&E must consider how their AMI Plan comports with these requirements. Based on those considerations, the Companies may wish to file a supplement to their AMI Plan that describes how their Plan comports with these requirements, or alternatively, how it is amended to do so.

<u>The Commission orders</u>:

1. The AMI system requirements listed in Appendix I and as described in the body of this order are adopted.

2. Central Hudson Gas and Electric Corporation and Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc. shall make additional filings within 60 days of the date of this order, as prescribed by our previous orders; except that in making their filings, the companies shall not be required to file

revised benefit-cost analyses. The Secretary in her sole discretion may extend the deadlines set forth herein.

3. This proceeding is continued.

By the Commission,

(SIGNED) JACLYN A. BRILLING
Secretary

ADVANCED METERING INFRASTRUCTURE
MINIMUM FUNCTIONAL REQUIREMENTS

(a) AMI systems must be compliant with all applicable ANSI standards, Commission regulations and Federal standards, such as FCC regulations.

(b) AMI systems must provide net metering.

(c) AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with the auxiliary device if it is the only means of a visual read of consumption data.

(d) AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.

(e) AMI meters must have sufficient on-board meter memory capability to ensure meter data is not lost in the event of an AMI system failure and that the previous and current billing period of billing data is stored on the meter.

(f) AMI systems must have the ability to provide customers direct, real-time access to electric meter data. The data access must be provided in an open non proprietary format.

(g) AMI systems must have the ability to remotely read meters on-demand.

(h) At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.

(i) AMI systems must have two-way communications capability, including ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.

(j) AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network (HAN) to provide direct or customer-activated load control.

(k) AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.

(l) AMI systems must have the following security capabilities:
   (i) Identification - uniquely identify all authorized users of the system to support individual accountability;

(ii) Authentication – authenticate all users prior to initially allowing access;

(iii) Access Control - assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated;

(iv) Integrity – prevent unauthorized modification of data, and provide detection and notification of unauthorized actions;

(v) Confidentiality - secure data stored, processed and transmitted by the system from unauthorized entities;

(vi) Non-repudiation - provide proof of transmission or reception of a communication between entities;

(vii) Availability - ensure that information stored, processed and transmitted by the system is available and accessible when required;

(viii) Audit - provide an audit log for investigating any security-related event; and

(ix) Security Administration – provide tools for managing all of the above tasks by a designated security administrator.