conEdison
a conEdison, inc. company

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March 28, 2007

Hon. Jaclyn A. Brilling,
Secretary
State of New York Public
Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

RE: Case 94-E-0952 -In the Matter of Competitive Opportunities Regarding Electric Service
Case 00-E-0165 -In the Matter of Competitive Metering

Dear Secretary Brilling:

Enclosed please find an original and fifteen copies of a Plan for Development and Deployment of Advanced Electric and Gas Metering Infrastructure by Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., being submitted at the direction of the Public Service Commission by its order of August 1, 2006, in the above referenced proceedings. Please acknowledge receipt by stamping and returning the enclosed copy of this letter in the self-addressed envelope provided.

The Companies will provide their submittal by email to all parties on the Active Parties list for these cases.

Sincerely,
/s/Sara Schoenwetter

c: Active Parties List, Cases 94-E-0952 and 00-E-0165

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 94-E-0952 -	In the Matter of Competitive Opportunities Regarding Electric Service
Case 00-E-0165 -	In the Matter of Competitive Metering

PLAN FOR DEVELOPMENT AND DEPLOYMENT OF ADVANCED ELECTRIC AND GAS METERING INFRASTRUCTURE BY CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. AND ORANGE AND ROCKLAND UTILITIES, INC.

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March 28, 2007

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PLAN FOR DEVELOPMENT AND DEPLOYMENT OF ADVANCED ELECTRIC AND GAS METERING INFRASTRUCTURE BY CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. AND ORANGE AND ROCKLAND UTILITIES, INC.

By Ordering Clauses 1 and 3 of its August 1, 2006, Order Relating to Electric and Gas Metering Services (the "Metering Order"), the Public Service Commission (the "Commission") directed Consolidated Edison Company of New York, Inc. ("Con Edison") and Orange and Rockland Utilities, Inc. ("Orange and Rockland") (together referred to as the "Companies") to submit a plan for the development and deployment of an advanced electric metering system, including automated meter-reading ("AMR") capability, and an assessment and plan, if warranted, for the development and deployment of an advanced gas metering system, including automated meter-reading capability. The Companies' plans are submitted in this filing.

SUMMARY OF PROPOSAL

In their plans, the Companies propose to install an advanced metering infrastructure ("AMI") throughout their service territories in New York on both electric and gas services. The Companies have about 3.6 million electric meters and nearly 1.2 million gas meters between them, arrayed over nine counties in New York State. Under this proposal, all locations served by these meters would have advanced meter functionality by 2014.

The AMI business case for this proposal finds an AMI installation cost-effective by considering both the Companies' direct operational savings and other benefits to the Companies, their customers, the market, and society generally. These other benefits, which are generally more complex to measure, are sufficient to offset the difference between the projected cost of the AMI and the predicted operational savings.

The Companies have identified technologies that currently appear to provide a “best fit” for their AMI system. However, because AMI technology has been developing rapidly, and much of it is untested in utility service territories resembling the Companies’ service territories, the Companies propose to undertake four pre-deployment demonstrations. These projects will allow the Companies to evaluate the performance of selected technologies, the integration of meter data derived from AMI into their “back-office” systems, and customer response to additional information about their utility usage. Provided the results of these demonstrations support the Companies’ assumptions, and the Companies have a reasonable opportunity to recover all capital costs associated with the AMI and all incremental operations and maintenance (“O&M”) expenses incurred in the implementation and operation of the AMI, the Companies will proceed with deployment.[1]

BACKGROUND

Many utility customers have had the opportunity for nearly ten years to obtain meters with added functionality for various purposes, through utility upgrade programs and through the services of Meter Service Providers (“MSPs”) authorized by the Department of Public Service. However, the demand for such meters has been limited, and MSPs have been involved in the provision of very few meters in the Companies’ service territories. Customer interest in interval

[1] Provided that the technology assumptions are borne out by initial operating results, the Companies would continue to install the AMI while testing and evaluating customer response during the first year of pre-deployment project operation.

meters has been associated primarily with participation in demand response programs that require hourly meter data.[2]

Because the market for competitive metering services has not developed as anticipated, the Commission recently reviewed its prior objection to utility investment in advanced metering. In the Metering Order, the Commission concluded that all utilities should consider the installation of AMI. The Commission directed each utility to propose a plan for development and deployment of AMI on electric systems to the extent feasible and cost-effective and to assess and plan for the implementation of AMI on gas systems, if warranted.

Con Edison has some experience with meter-reading automation through its 2003 pilot program to automate reading of about 93,000 electric and gas meters in northern Westchester County. For most electric meters, AMR required that Con Edison add a communications module that can transmit the meter data to equipment in a vehicle passing by ("Mobile AMR"); rather than installing the module in the field, the Company replaced the existing meter with a meter that had already been retrofit with the module. Gas meters were generally modified in the field by adding the AMR module. For some types of older vintage gas meters, field retrofit was not an option, and a new meter already equipped with an AMR module had to be installed. AMR is proving to be cost-effective in its initial deployment; it is already providing Con Edison with most of its anticipated savings in meter-reading expenses consistent with the Company's original assumptions. In its 2004 electric rate case, the Company proposed to expand the installation of AMR-equipped electric and gas metering in order to automate meter reading throughout Westchester County. The Commission authorized this investment in its order on Con Edison's

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[2] Customer costs for interval metering in this application have been subsidized through the System Benefits Charge program operated by the New York State Energy Research and Development Administration.

Electric Rate Plan[3] and in its Metering Order. The Company began the expansion project in May 2006, and, to date, approximately 50,000 additional electric and gas meters have been installed or upgraded in the Rye meter-reading area of Westchester. The Company expects to complete installation of about 200,000 meters in the Rye area by the end of 2007.

DEVELOPMENT OF AMI/AMR PLAN

Following issuance of the Metering Order, the Companies engaged KEMA, a consulting firm with a dedicated AMI practice, to assist them in research and analysis to develop a feasible and cost-effective AMI plan for their electric and gas services. The principal aspects of this work were (1) the identification of (i) the goals for AMI and (ii) the potential costs and benefits of an effective and efficient advanced metering system, (2) the identification of appropriate technology, and (3) the analysis that reflects these findings and is set forth in the business case for this proposal.

This filing describes the goals identified for AMI, the potential costs and benefits of an effective and efficient electric advanced metering system, the treatment of gas metering in such a system, the technology issues confronted in the design of AMI systems for the Companies' service territories, and the Companies' proposals for (1) testing the selected communications technologies in pre-deployment demonstration projects and (2) developing data reflective of customer response to new rate forms and the additional information available through an AMI system. The Companies also propose mechanisms for the recovery of capital investment and operations and maintenance ("O&M") costs of the AMI systems being proposed.

[3] Case 04-E-0572, Order Adopting Three-Year Rate Plan (March 24, 2005).

THE AMI/AMR PLAN

Goals for AMI

From their review of the potential functionality of an advanced metering infrastructure, the Companies believe that AMI will provide a basis for cost-saving changes in many areas of customer operations as well as enabling benefits for customers, the environment, and society generally. The primary change in utility operations will be the substitution of automated reading of electric and gas meters for manual meter reading. Other customer service goals expected to be realized with the implementation of AMI include substantial reduction in (i) the number of estimated bills issued and the concomitant reduction in customer contacts regarding estimated usage, (ii) disputes regarding responsibility for service left "hot" after a customer vacates a premises and before a new customer requests service, and (iii) more frequent and granular consumption information that is expected to have many uses.

Through the Meter Data Management System ("MDMS") component of the AMI system, the Companies are anticipating that all customers, their energy consultants, and energy services companies ("ESCOs") will have access to desired usage information from AMI in a convenient form and without distinction based on energy provider. The enhanced usage information available to customers and, therefore, customers' more informed response to demand response programs, are expected to yield reductions of electric system load and market price peaks to the benefit of the market and all electric consumers.

AMI is also expected to provide the Companies with enhanced distribution system information relating to power outages and restoration, power quality, and meter tampering, as well as facilitating participation in energy management programs through manual action by customers, preprogramming, or remote control. Such facilitation is consistent with the United

States Department of Energy's recommendations[4] developed as a result of the federal Energy Policy Act of 2005 and the price-responsive load programs of the New York Independent System Operator.

System and service area considerations

An AMI requires one or more types of meters, communications systems, and meter data management systems. The selection of each component of the infrastructure depends on different factors. For instance, selection of the meter depends on the functionality desired and its ability to operate with the selected AMI communication capability. This combination can be achieved either by adapting a meter with a communications module (the usual approach for gas meters) or by acquiring a meter that has an integrated communication capability as part of its design (the usual approach for electric meters).

Selection of the communications technology is more complicated. The selected technology will constitute the backbone of a system that must transmit meter data without interruption or alteration.[5] There are generally two components to the communications system: local area network (LAN) communications and wide area network (WAN) communications. The LAN is used to transmit data from the meter to some local collection point, whereas the WAN is used to transmit data from the local data collection point to a data repository, such as an MDMS. At the present time, every provider of AMI systems has a unique communications method for the LAN portion of the solution. The WAN connections considered for this proposal would employ standard network communication arrangements generally available from a variety of sources.

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[4] United States Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A report to The United States Congress pursuant to Section 1252 of the Energy Policy Act of 2005" (Feb. 2006).

[5] The communications infrastructure proposed could also be used for other electric and gas applications.

The selection of a specific LAN communications technology involves many considerations, including factors related to meter location. In Con Edison's service territory, the building stock and population and meter density differ greatly from neighborhood to neighborhood. Some areas may be described as "vertical urban" and others as "horizontal urban." The former areas consist primarily of high-rise multi-story office and residential buildings, where meters may be located in meter rooms on upper-story floors, while the latter areas include one-, two-, and three-family houses, garden apartment complexes, four to six-story multiple dwellings, and small shopping strips, where meters may be located in basements and only occasionally outdoors. Other areas are considered "suburban," and others that are even less dense may be termed "rural;" in both types of areas, meters are generally (but not always) located outdoors. In Orange and Rockland's service territory, some areas are suburban and others are rural.

AMI system manufacturers' experience is predominantly with electric radial distribution systems common in suburban and many urban areas. Many AMI systems have not been adequately tested in network distribution systems like Con Edison's, which have characteristics that can adversely affect the performance and functionality of offerings that use the electrical network as a communications medium. The underground network distribution system that is found in the majority of Con Edison's service territory also presents technical challenges to radio frequency ("RF") communications technologies used for AMI, particularly where meter density is high or meters are located in multiple stories below grade or where building construction may impede transmissions. Because of the lack of homogeneity across their service territories, the Companies are proposing AMI systems with different LAN communications methodologies that address the particular characteristics of each type of area.

WAN communications are equally important and must be selected carefully. Because of the meter density in many areas of the service territory, the local data collectors will be required to receive data from large numbers of meters. Consideration must be given to how well the WAN communication alternatives handle large quantities of data from the data collectors. It is anticipated that a common-carrier wireless data path may be the most suitable solution, with the possibility that a metropolitan wireless network may be a viable alternative in Con Edison's New York City region. Con Edison will design a pilot project, in addition to those described below, that will use this New York City wireless network for wide-area communications when it is available.

Upgrading of AMR system

Given Con Edison's substantial progress in implementing a Mobile AMR system in Westchester, the Companies considered how best to upgrade the functionality of that system if an AMI system were to be implemented elsewhere in the Companies' service territories. Mobile AMR of the type installed by Con Edison can theoretically migrate to "fixed network" architecture, providing a system that offers many of the functions that would be available from AMI systems having full two-way connectivity. This "virtual AMI" system solution is available from the same technology vendor selected for the original Mobile AMR system. Con Edison would establish a fixed network by installing pole-top data collectors to receive meter data frequently and return the retrieved data to the utility. This approach preserves the investment already made in the meter sets while further reducing operating costs for meter reading by avoiding the need to drive by the meters. The meters in this fixed network can be read more frequently than once per monthly billing cycle, the current access frequency, thus providing much of the same type and timeliness of meter data as AMI systems that have a bi-directional communications link to each meter. While direct interaction with each meter in an AMI system does offer more flexibility and greater functionality, many of the benefits of the AMI system can also be realized with this fixed network configuration.

Technology Assessment

Traditionally, utilities have used single purpose systems to satisfy specific business needs such as outage management, distribution automation, and general purpose data acquisition. These solutions generally involve a hardware device controlled by a stored program, a communications network (telephone, cellular, powerline communications, Ethernet, or other network service), and an appropriate information reception, execution, processing, and distribution system (data warehouse, back office, head-end, or master station).

Utilities have a fundamental business requirement to read meters so they can render accurate bills to their customers. AMR systems provide the utility with the ability to remotely gather data on consumption and indications of meter tampering; they can also relay other core static meter functions. The chart below lists the additional functionalities that are enabled by migrating from Mobile AMR to a fixed network and those that are fully enabled by AMI.

Functionality Available	System Architecture			
	Mobile AMR	Fixed Network	RF Point to Point	RF Mesh
Integrated remote service reconnect			✓	✓
Advanced (time-based) rates		✓*	✓	✓
Distributed Generation detection and control			✓	✓
Remote meter programming			✓	✓
Power Quality monitoring/reporting			✓	✓
Home area network interface			✓	✓
Enhanced security compliance			✓	✓
Daily or on-demand reads		✓	✓	✓
Interval data		✓	✓	✓
Outage notification		✓	✓	✓
Load profiling		✓	✓	✓
Automated monthly reads	✓	✓	✓	✓
Tamper reporting	✓	✓	✓	✓
Improved meter read accuracy	✓	✓	✓	✓

* To be validated in pre-deployment demonstration projects.

Automated meter reads in a Mobile AMR or Fixed Network system, as indicated above, are accomplished using a proven one-way data acquisition system in accordance with monthly billing schedules. The migration from AMR to AMI is characterized by more robust communications means that enable more frequent interaction, both scheduled and by exception, and other functionality between the meter and the MDMS and more traditional backend systems. These differences are shown in the columns identified as Point to Point ("P2P") and RF Mesh.

The basic meter-reading functionality generally applies to both electric and gas meters in AMR systems. However, because gas meters are not powered from the electric grid, their communications functionality must have another source of power, usually a battery. In AMI systems, similar to an AMR system, the need to have a battery-operated element within the gas meter places key restrictions on communications functions that can be performed by the AMI gas meter, such as limiting the transmission signal power which, in turn, limits the distance the signal containing the information can travel before it needs to be received by a collection device. This power limitation precludes the gas meter from acting as an active relay link in an AMI network (sometimes referred to as a "mesh point"[6]). If these limits were not observed, the battery would have to be replaced more frequently, and the higher operational costs associated with more frequent battery replacement would reduce the potential net benefit of the investment in AMI for gas meter reading alone.

Electric meter technology has been evolving and continues to evolve. Along with the transition from electro-mechanical to solid-state devices, meter communication elements have become more available and are becoming less expensive. With the integration of communications, AMI technologies can have functionality beyond the utility's monthly revenue

[6] As will be explained below, in an RF Mesh network, the electric meter can relay data from a gas meter or another electric meter to the data collector, a function that makes the electric meter a "mesh point."

meter-reading requirements. AMI systems open the possibility of integrating a load-limiting functionality, along with the ability to interact with the gas meter and other devices in the customer's premises. Industry is moving to communications featuring open architecture and device interoperability. This is critical to achieving these benefits.

While virtual AMI provided by a fixed network is expected to be able to support time-of-use rate forms, the intelligence, processing power, storage, communications, and time keeping that can be incorporated in AMI-enabled meters can readily support a variety of other time-based tariff programs, such as critical peak pricing. Further, the AMI facilitates customer price response and participation in demand response and demand-side management programs. If properly equipped, many AMI devices can interface directly with premises-based devices such as programmable communicating thermostats and can interact with other display and interactive devices. Therefore, it is possible for consumers to set simple rules-based actions for their loads and better manage their energy costs through automated control technology. This functionality is a significant enhancement over simple direct load-control functions for both customers and the utility.

AMI also provides better utility oversight of customer performance by enabling the monitoring of the individual load prior to the load control event and the load reduction following a control command. This measurement and verification function adds a greater level of confidence over one-way direct load control programs, where the efficacy of such control efforts can only be measured indirectly after the command is executed and the reduction occurs. This ability to measure the individual effect of the execution of the load control command at each meter can also reduce the impact of any "free-riders" on these programs.

In addition, AMI functionality can enable many utility-centric and operations-related services, including:

- Monitoring some types of distribution system conditions and events, such as power quality disturbances,
- Improving the reporting of electric outage conditions and interruptions,
- For reliability purposes, remotely disconnecting or limiting and, with safeguards, reconnecting electric service through the addition of an integrated service switch,
- Capturing and reporting time-stamped load monitoring data for system analysis and planning, and
- Providing the ability to remotely upgrade meters or device components without the need to make costly field visits for meter replacements or upgrades. Such upgrades may be due to industry changes to security algorithms, adjustments to daylight savings time (for time-based rate offerings), and the Companies' desire to make changes to operating characteristics and algorithms inherent in these devices.

Communications Technologies

The Companies considered several different communications technologies, which are described below.

Telephone and Digital Cellular

A public communications system, such as a standard telephone line or a wireless cellular network, can be used to directly link individual meters to utility back-end systems. While the Companies currently use telephone service for meters on certain types of electric and gas service, the general use of this communications method for a mass-market infrastructure would be costly.

Moreover, although the monthly costs of telephone lines have decreased over the years, a growing trend in the residential market is for the traditional “land-line” to be replaced with a cellular phone, thus eliminating the affiliation of a phone number to a fixed location. The costs of a cellular connection have decreased as well. However, the recurring fees for use of this method as a data collection alternative for mass-market meter reading are substantially greater than other network arrangements considered. Nevertheless, both telephone and cellular techniques remain viable options for special cases where another type of AMI communications is impractical or impossible.

Mobile and Fixed Network Radio Frequency (“RF”)

In Westchester, Con Edison currently uses AMR in a drive-by mode, sometimes referred to as Mobile AMR. This method requires a vehicle equipped with instrumentation capable of gathering meter data to be driven past meters that are equipped with a low-powered RF module operating on an unlicensed frequency. The meters (either gas or electric) can either be awoken to broadcast information (this is the typical arrangement with battery-powered units in gas and water meters) or they can continuously broadcast or “bubble up” their information (this is the more typical method for electric meters where the power consumption of the RF module is not an issue). Because of the need to pass near each meter to obtain its reading, Mobile AMR is typically used for reading meters once each billing cycle.

A “fixed network” is established in an area with RF-based AMR meters with the installation of collectors located on utility pole tops, utility towers, or similar structures. The network can then effectively operate as a remote collection system, that is, one that is capable of gathering information from meters on a more frequent basis and of communicating this data to the master station and responding to requests for meter data that is locally stored at the collector.

RF Mesh

In this technology, the meters have the ability to relay data both from their own registers and from other meters. This arrangement creates a network among end-points through meter-to-meter communications. This interconnected network is used to extend the range of the AMI modules, optimize the communication paths, and reduce the number of pole-top data collectors required (as compared to the fixed network described above). Communications reliability is generally improved because the messages are not assigned a specific path but can be routed through the "best" path in the network at the time of transmission. By designating key points in this mesh network as "take-out points," this configuration can reduce the total number of collectors and master-station relay points (concentrators) that would otherwise be required in a more typical fixed network. These take-out points are typically mounted on utility poles or similar structures.

RF Point to Point ("P2P")

AMI systems in a P2P architecture use higher-powered RF modules operating in a licensed frequency to communicate with data collectors. Systems with this configuration can enable a full two-way network. Additional functionality, such as soliciting an ad hoc individual meter-reading interrogation, querying the meter to provide information on power quality, and communicating directly with individual peripherals, is based on such a system's capability to send information to or receive information from specific points. This higher-powered configuration can communicate directly with many more meters and requires fewer but commensurately more costly radio transceivers than a fixed network.

Broadband over Powerline ("BPL")

New techniques can enable a high-capacity data network to be created in the existing electrical network. These "broadband over powerline" networks provide high-speed connectivity. Many utilities indicate a growing interest in and early use of these techniques for utility-oriented services such as electrical distribution asset monitoring, substation video surveillance services, and AMI. However, this communications technique has a high level of uncertainty both in technical and total functionality in Con Edison's network distribution grid. Since BPL is still evolving and the Companies' evaluation of this technique is in the early stages of feasibility studies, this method was eliminated from consideration in the Companies' current business case. Although BPL may be viable in radial distribution networks, the present costs of this communications infrastructure and the greater cost of BPL-enabled meters make this technology significantly more costly than the other AMI methods considered. The Companies will continue to re-evaluate this method because this technology offers some key advantages: 1) it uses the physical electric distribution network already in place, thus reducing the need to build a communications network overlay; 2) in many cases, the necessary communications data collection points are already on Company property and are connected to the Corporate WAN; and 3) the large bandwidth afforded by this approach would permit AMI to share the communications infrastructure currently used by existing operational applications like outage management and distribution network monitoring.

Powerline Carrier ("PLC")

PLC likewise uses the existing electrical distribution network as a means to communicate to and from meters. However, this technology operates at a lower frequency range, providing a lower-speed communications bandwidth. This system uses vendor-supplied coupling equipment and sensors at key points within the distribution network. These devices communicate with meters that contain the powerline signal decoding and modulating unit. When a specific meter that corresponds to a designated address (or group of meter addresses) is interrogated, it interprets the respective command and sends a message (or messages) in response to this poll.

For other devices that are not connected to the power line, such as gas meters, a low-power radio transceiver included in an adjacent or nearby electric meter may allow the electric meter to act as a gateway or relay for these other devices. This secondary RF-link enables the utility to communicate, albeit indirectly, with gas meters, water meters or customer-premises devices, such as thermostats or other peripherals.

At the substation, there is a communications link that provides a data path to the back office. This link can use any common data network means that is appropriate, including, but not limited to, telephone landline, wireless telephone, WiFi or other WAN connection.

Unlike BPL, the modulation method used by PLC systems does not require the deployment of signal repeaters along the distribution network. However, the PLC system is also optimized to perform on radial distribution networks and, therefore, may not be suitable in Con Edison’s network distribution areas.

Meter Data Management

An MDMS is an essential component of an AMI system to facilitate data accessibility and full benefit realization. This is particularly important because of the Companies’ need to have multiple AMI solutions to address the communications issues and to establish interfaces from the different AMI solutions to multiple back office systems.

The MDMS would be designed to manage and retain the volumes of information that would be gathered from endpoints. Because AMI is expected to provide more discrete and more frequent information from endpoints, requirements for storage and processing would exceed the current capacity of many of the Companies' existing back-office systems. The MDMS would preclude the additional data from overburdening the Companies' legacy systems by providing intermediate data processing capability and storage facilities. Moreover, by virtue of the MDMS's capacity to provide an interface for AMI data from multiple AMI solutions to various utility back-office systems, the Companies would not have to create separate and redundant interfaces for each technology solution and each legacy system.

The MDMS would also establish the basis for access to meter data for relevant Con Edison operations, customers, their consultants, and ESCOs. Most MDMS offerings provide the necessary Internet-based tools and interfaces to enable these data-access functions.

BUSINESS CASE

The fundamental utility need to efficiently and accurately gather data at every metered service delivery point is key to building an advanced metering infrastructure. However, unless the utility can derive more benefit from AMI than the automation of its meter-reading function, the incremental cost of an advanced metering infrastructure can make the business case economics of such a system a challenge. Justification for the incremental investments required for AMI must be sought by closely examining, evaluating, and quantifying all the potential benefits that can be derived from an AMI system. While many of these other benefits can be attributed to other components of the utility's business, some are attributable to effects on external entities.

To develop the business case, the Companies examined the various technology choices, their suitability within their service territories with consideration of the meter locations, electric network distribution characteristics, population of electric and gas meters, and the costs of the components of the AMI solution. In a similar manner, the benefits that AMI would enable were identified, assessed, and, where possible, quantified with greater or lesser certainty.

Communications Technology Selections

Advanced metering systems require robust communications to provide the utility with the ability to capture remote parameters and meter data for various purposes. In the selection of an appropriate communications technology, it is critical to ascertain the effectiveness of the AMI when presented with the potentially large volume of data and the increased frequency of data collection from these meters. The evaluation of communications technologies currently available in the market has required consideration of the topography of the Companies' service territories, as well as meter density and meter location within customer premises. Given the variety in these factors in the five boroughs of New York City and the Counties of Westchester, Orange, Rockland, and Sullivan, the Companies have faced challenges predicting, with the greatest degree of accuracy practicable, if a given system would provide adequate coverage, how many systems can be managed reasonably and effectively, and how multiple communications methodologies would affect the cost of deploying and maintaining the AMI system. The Companies' "Optimal Solution" choices and the rationale for their selection, based on the Companies' evaluation of the communications technologies available and their suitability for the conditions identified, are described below:

AMI Deployment Assessment							
	Manhattan	Brooklyn	Bronx	Queens	Staten Island	Westchester	Orange & Rockland Service Territory
Electric Distribution Structure	Network	Network	Network	Network	Radial	Radial	Radial
Dominant Topography	Vertical Urban	Horizontal Urban	Horizontal Urban	Horizontal Urban	Suburban	Suburban	Suburban and Rural
Optimal AMI Technology Solution	RF P2P	RF Mesh	RF P2P	RF Mesh	RF Mesh	Fixed RF Network / RF P2P	RF P2P

RF P2P for Manhattan and the Bronx

Because most meters in this area are located either in a vertical or horizontal urban or subterranean environment, an RF P2P system appears to be the most practical choice. This AMI system uses FCC-licensed frequencies that are expected to provide more effective in-building penetration and coverage and to require fewer towers than other RF technologies.

RF Mesh for Brooklyn, Queens, and Staten Island

Since RF mesh networks rely on peer-to-peer networking among close-proximity meters, the horizontally dense meter array in these areas of urban topography may be most favorably served by this technology. Although Staten Island does not have any Con Edison gas meters and is a radial electrical distribution network, RF Mesh was chosen over other alternatives to minimize the total number of technology considerations for Con Edison.

Fixed RF Network for the existing Mobile AMR-enabled meters in the Peekskill and Rye areas of Westchester

The selection of this technology for this area was driven by the expected economic benefit of leveraging the existing investment in AMR technology already in place with the drive-by system. This approach enables Con Edison to realize a large majority of the features desired in the short term without stranding the metering assets recently deployed.

Con Edison's 2004 electric rate case filing projected operational savings equivalent to the cost of the proposed Mobile AMR system in Westchester. Con Edison expects to meet this objective. The installation and operation of a fixed RF Network will add costs associated with the installation and operation of this communications infrastructure. These incremental costs marginally lengthen the projected recovery period. However, it is anticipated that as the investments in the Peekskill and Rye areas are matched by savings, an evaluation of the efficacy of the fixed network will be made. If appropriate and justified by incremental benefits, these AMR-enabled meters may be replaced with an RF P2P.

RF P2P for Orange and Rockland and Areas in Westchester that do not have AMR-enabled meters

While these radial electric service areas are candidates for a PLC solution, the choice of P2P was made based on lower infrastructure and end-point costs. Additionally, the need to separately support a different AMI communication method in these service territories from those proposed for other areas of the Companies' territories would add complexity to meter deployment logistics, erosion of the Companies' economies of scale, and increased back-office systems integration costs.

Cost Analysis

The assessment of the cost-effectiveness of an advanced electric- and gas-metering infrastructure has been a complex undertaking for several reasons. Cost estimates depend on the identification of the metrology and, more important, the communications system or systems and the MDMS to be employed. Choosing among the available systems requires an understanding how each possible system would be arrayed across the specific topography and meter locations in a utility's service territory in order to provide the desired degree of timeliness and consistency in the communication of meter data. Choosing among these RF systems, for which there is little or no experience in a communications-congested and challenged area like New York City, which has a significant network distribution system (in contrast to a radial distribution system) and meters located both many levels below and many levels above ground, required some estimation of technical capability and minimum equipment requirements. Thus, because of the lack of certainty with respect to the physical configuration of the AMI systems, there is a corresponding uncertainty in projecting the costs of implementing such systems until these systems can be validated. The information for estimating the equipment costs was developed from non-binding estimates provided by vendors for their respective components based on their limited evaluation and/or assumptions and without time to conduct proper propagation studies.

The cost analysis was carried out by projecting the system costs on an overall basis for Con Edison and Orange and Rockland (referred to here as "common costs") and forecasting other costs as they are expected to be applicable specifically to each of the seven distinct areas within the Companies' service territories, that is, the County of Westchester and the five boroughs in the City of New York for Con Edison and the combined Counties of Orange, Rockland, and Sullivan for Orange and Rockland. Because of the allocation of costs between the Companies, no area can be looked at independently without consideration of the impact of the loss of scale.

Consistent with manufacturers' representations and the regulatory filings made by other utilities regarding expected equipment life[7], the cost analysis assumed a meter equipment life of 15 years, a communications infrastructure life of 15 years, and an information technology hardware life of five years. The analysis also assumes a seven-year system-wide deployment

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[7] Southern California Edison Testimony Supporting Application for Approval of Advanced Metering Infrastructure Pre-Deployment Activities and Cost Recovery Mechanism. Volume 3 – AMI Preliminary Cost Benefit Analysis (Dec. 21, 2006).

schedule commencing in 2007 for Con Edison and an eight-year implementation schedule commencing in 2007 for Orange and Rockland with annual inflation at the rate of 2.6% applied to O&M costs. A particular focus in the cost model was establishing the communication requirements for the gas meters so they would maintain operational functionality within the projected 20-year life span of the batteries.

The Companies identified the following key cost elements as necessary components for analysis:

Metering Equipment (capital expenditures $379.5 million, ~ 53% of total costs)

The cost of metering equipment, even without consideration of installation cost, is the single most significant cost factor in the model. Meter costs are dependent on the communications technology selected because of the need to incorporate into the meter the equipment necessary to implement that specific technology. The cost for a residential non-network electric meter ranges from approximately $40 to $100, exclusive of installation costs. The cost of a residential electric network meter is approximately $70 to $140, exclusive of installation costs. The meters for commercial and industrial ("C&I") service are generally twice the cost of a residential meter. Moreover, meters for C&I customers can vary significantly, depending on the characteristics of the electric service taken (e.g., voltage, number of phases, and whether the service is multi-metered) and service classification (e.g., demand register and interval data requirements).

Most of the gas meters would be retrofit with new registers wherever possible, using a module that is compatible with the communications infrastructure. The incremental module cost required to retrofit an existing gas meter is in the range of $50 - $60 for a residential meter and $100 - $125 for a commercial meter, exclusive of installation costs. In some cases, older vintage "tin-case" gas meters, typically in use on low-usage accounts, cannot be directly retrofit with an AMI module. To overcome this, a number of alternatives were considered. One possible solution is the replacement of these gas meters with new meters that would have the communications capability already included. However, the incremental cost of buying and replacing these meters would be substantial[8] and has not been included in the business case. To address this issue, the Companies are investigating technology solutions that would permit these tin-case meters to be AMI-enabled at a lower cost than replacement.

Meter and Data Collector Installation (capital expenditure - $88.5 million, ~12% of total costs)

Estimated costs for installation of an AMI equipped electric meter range from $20 for a residential meter to $50 or more for a commercial meter. Retrofitting an existing gas meter with a register that has communications capability is in the same range. It was assumed that the installation of the requisite hardware and equipment for the communications infrastructure would be outsourced. These costs are dependent on the system type selected.

Meter Communications Infrastructure (capital expenditure $41.2 million, ~ 6% of total costs)

This cost represents the capital required to purchase the LAN and WAN communications network infrastructure. It is dependent on the technology chosen, meter density, and on the type of network used in each geographic area. The present-value cost for infrastructure ranges from $3 to $16 per metering point. Areas that have both electric and gas meters would share the same infrastructure costs.

[8] In addition to the replacement meter cost, the labor cost to replace an entire residential gas meter is estimated to be greater than $100.

Operations and Maintenance (expense present value over 15 years $92.8 million, ~ 13% of total costs)

The on-going costs to operate and maintain the AMI system include monthly communication fees for use of the LAN infrastructure (as required) and the WAN to transmit the meter information, communications site lease payments, software maintenance costs, meter maintenance and testing, and similar expenses over the life of the project.

Meter Data Management System (capital expense $17.0 million, ~ 2% of total costs)

The costs for the MDMS include the costs of a central back-office repository for meter data and the work related to the integration of the MDMS into existing back-office systems. The capital cost of this element includes a fully redundant system (production and hot standby) as well as a development/test platform. Since the Companies are planning that the MDMS would be common to Con Edison and Orange and Rockland, for the purpose of the analysis the cost of this element was pro-rated to each area, based on the meter count for each area.

Labor costs ($86.1 million over the 15-year period, ~ 12% of total costs)

To support the AMI project, additional utility personnel would be required for program management and administration, including technology management and the supervision of installation contracts, and for field planning, meter inspection and testing, programming, and rate design. Because this organization would support the entire AMI deployment, these costs were applied on a meter count pro-rated basis to each area.

Other costs ($7.7 million over the 15 year period, ~ 1% of total costs)

These costs include facility costs, training, and tools.

General Cost Factors

AMI technology is rapidly evolving. As more and more utilities fully examine, explore, and deploy AMI, advancements will be made in this area. Utilities are driving some of these changes, as demonstrated by the California utilities' requests for additional functionality, such as expanded memory for time-of-use data accumulation, which is now being incorporated as a standard meter offering.

Additionally, the pricing of electronic and communications equipment has generally moved downward in recent years. For example, until recently, the incorporation of a service switch as part of the under-the-glass meter electronics would have increased the cost of such a meter by over $200. Today, many vendors are estimating costs of less than $50 for this functionality for residential electric meters on customer services of 200 amps or less. If these trends continue, it is possible that the system(s) implemented over the term of this proposal may incorporate equipment not yet commercially available and with costs that are lower than those seen today.

Cost Area	Present Value * over 15 years ($ Million)
Metering Equipment	$379.5
Meter and Data Collector Installation	$88.5
Meter Communications Infrastructure	$41.2
Operations and Maintenance	$92,8
Meter Data Management System	$17.0
Labor costs	$86.1
Other costs	$7.7
Total Costs	**$712.8**

* Present value to 2007.

Benefit Analysis

In the assessment of potential benefits that could be achieved through AMI, the Companies examined, evaluated, and projected economic realizations in a number of categories. The savings were grouped into the categories of Companies' Realizable Operating Benefits, Companies' Future Operating Benefits, Societal Benefits, and Societal Future Benefits. Some of the Future Operating Benefits are expected but presently pose a greater challenge to accurately quantify, and no dollar value was assigned to them.

Companies' Realizable Operating Benefits

Elimination of Manual Meter Reading ($266.4 million, ~52% of total Companies' realizable operating benefits)

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 maintenance/upgrade expenses for current meter-reading devices and yearly salary increases for meter readers and supervisors.

Reduction of Off-Cycle Reads ($12.3 million, ~2% of total Companies' realizable operating benefits)

Because AMI can provide daily and on-demand reads, follow-up costs related to meter checks and re-reads can be reduced.

Reduction of Estimated Bills ($12.1 million, ~2% of total Companies' realizable operating benefits)

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.

Reduction of Field Service Orders ($2.4 million, < 1% of total Companies' realizable operating benefits)

AMI will enable O&R to avoid field service visits triggered by questionable estimated readings on customer move-outs/move-ins.

Increased Revenue Due to Improvement in Meter Accuracy ($42.1 million, ~8% of total Companies' realizable operating benefits)

Evidence shows that electro-mechanical electric meters begin to underrecord 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. Moreover, 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. This benefit would also be reduced based on actual revenue increases determined in each rate year.

Deferral of Metering Capital Costs ($140.3 million, ~27% of total Companies' realizable operating benefits)

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. This capital deferral is offset by the annual failure rate of newly installed AMR/AMI equipment (e.g., meters, telecommunications).

Reduction of Call Center Contacts for Bill-Related Calls ($4.1 million, ~1% of total Companies' realizable operating benefits)

Estimated meter reads often generate customer calls associated with billing issues.

With monthly, daily, or more frequent reads from AMR/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.

Reduction of Compensation/Claims for Meter Reading ($6.0 million, ~1% of total Companies' realizable operating benefits)

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.

Reduction of Load Research Costs ($8.5 million, ~2% of total Companies' realizable operating benefits)

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.

Reduction of Revenue Losses from Unoccupied Premises ($8.7 million, ~2% of total Companies' realizable operating benefits)

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.

Reduction of Handling Time for Call Center Calls Regarding Power Quality Issues (< $0.1 million, < 0.1% of total Companies' realizable operating benefits)

Customer Service Representatives' access to on-demand power quality data or power loss flags could reduce call-handling time for power quality-related calls.

Reduction of Nested-Outage Restoration Time (<$0.5 million, ~0.1% of total Companies' realizable operating benefits)

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. 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.

Reduction of False Outage Dispatches ($1.3 million, ~0.3% of total Companies' realizable operating benefits)

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.

Increased Revenue Due to Reduced Outage Restoration Time ($1.3 million, ~ 0.3% of total Companies' realizable operating 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.

Reduction of Long-Term Outage Response Time ($1.7 million, ~0.3% of total Companies' realizable operating benefits)

An AMI communications system can be used to query individual meters (or meter status in the meter data collection system) to achieve a level of knowledge about power outage status. After major events, this capability could be utilized along with other AMI-related data to reduce long-term outage restoration activities, thereby decreasing the cost of using mutual aid crews.

Reduction of Costs to Support Other Initiatives ($2.5 million, ~ 0.5% of total Companies' operating benefits)

A number of initiatives and R&D projects may rely on the AMI communications network. The Companies presently incur costs for stand-alone, special data communications networks that are currently associated with some of these projects and initiatives. The use of the AMI infrastructure could potentially reduce the cost to gather data from various remote field devices.

Companies' Future Operating Benefits

Although the cost savings described above can be readily projected, other areas for savings cannot be so definitely quantified. For instance, although additional meter data may result in the detection of more instances of meter tampering, it is not practicable to estimate the incremental revenue to be received when a tampering condition is corrected. Estimates of these effects have been made where practicable but some of these impacts are also not clearly quantifiable.

Increased Customer Participation in Demand-Response Programs that would Defer Transmission and Distribution ("T&D") System Upgrades ($10.1 million, 94% of Companies' future operating benefits)

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 specific T&D projects, the increased load management participation and associated peak load reduction will generally help to defer T&D work over the long run.

Increased Customer Utilization of eCommerce Channels ($0.7 million, 6% of Companies' future operating benefits)

AMI and supporting systems can help increase customer utilization of eCommerce and decrease overall customer service costs. By supporting the provision of daily and interval energy data via an Internet portal for customer viewing, AMI is expected to increase customer interest in and use of eCommerce channels for other purposes.

Decreased Costs Through Use of Remote Reconnect/Disconnect or Load Limiting Devices (Not quantified in Companies' future operating benefits)

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. The Companies believe that they may realize cost savings and be able to improve network reliability if the electric meter included this additional device. However, because of the incremental cost and uncertainty of benefits, no specific benefits are reflected in this analysis.

Additional Reduction of Field Service Orders (Not quantified in Companies' future operating benefits)

If new electric meters are supplied with service switches, these benefits would include the avoidance of field orders for service reconnection.

"Societal" Benefits

Some cost reductions resulting from the implementation of AMI are expected to accrue to customers, the market, and to society, rather than to the utility. While many of these benefits are significant, they do not directly provide operational efficiencies to the Companies or constitute a contribution to operational benefits. These benefits include:

Avoided Capacity Costs due to Increased Load Management Participation ($122.8 million societal benefit, ~ 47% of total societal benefits)

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 notification (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. Unquantifiable reductions in wholesale market clearing prices may also result.

Avoided Capacity Costs by Managing Unforeseen Changes in End-use Devices that would Accelerate the Requirements for New Generation ($101.4 million societal benefit, ~39% of total societal benefits)

New technologies may be very energy intensive and have wide acceptance in a very short time frame. Some of the consumer wildcard technologies on the horizon for electricity include plug-in transportation alternatives, microbiological controls (for air quality or water filtration), and home entertainment. While none of these may provide the challenges/opportunities of the proliferation of the window air conditioning unit, it is important to recognize that AMI technology can play an important role in enabling demand-side technologies and choice and in controlling the impacts of new loads. The analysis also considers that weather anomalies affecting peak load may occur. While traditional load planning does consider some of these effects, there is a potential threat that higher summertime temperatures may extend for greater periods of time than current forecasts reflect. This increased stress on the networks could be obviated with more aggressive load management programs enabled by AMI.

Decreased Customer Costs Due to Improved Outage Management ($35.8 million societal benefit, ~14% of total societal benefits)

AMI allows a more effective dispatch of service crews to restore service in the event of an outage, thus reducing outage time. The customer costs are based on a recent study[9] that estimates the out-of-pocket costs by class of customer. Residential costs include the cost of batteries, flashlights, candles, and the need to buy prepared food.

[9] LaCommare and Eto, "Understanding the Cost of Power Interruptions to US Electricity Consumers," Lawrence Berkeley National Laboratory, LBNL-55718, Sept. 2004.

Commercial customers costs are based on, inter alia, work interruptions. Societal costs include wages and overtime for additional emergency personnel that may be required to protect businesses, direct traffic, and carry out other functions.

Decreased Electric Demand and Load that would Improve Environmental Conditions ($0.7 million societal benefit, ~0.2% of total societal benefits)

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.

Future Societal Benefits

Some of the identified benefits would result in savings to both customers and the Companies. In particular, the following area is noted:

Increased Customer Utilization of eCommerce Channels ($0.8 million societal benefit)

AMI and supporting systems can help customers through eCommerce functionality. Customers who become more accepting of eCommerce functions by viewing energy data may be encouraged to reduce their own costs for postage through Internet bill payment. The customer self-help capability of eCommerce channels would also be expected to increase and improve customer personal time efficiencies.

Benefit Area Breakdown (Present Value over 15 years*) ($million)				
Benefit Area	Realizable Companies' Operating Benefit	Companies' Future Operating Benefit	Societal Benefit	Societal Future Benefit
Elimination of Manual Meter Reading	$266.4			
Reduction of Off-Cycle Reads	$12.3			
Reduction of Estimated Bills	$12.1			
Reduction of Field Service Orders	$2.4			
Increased Revenue Due to Improvement in Meter Accuracy	$42.1			
Deferral of Metering Capital Costs	$140.3			
Reduction of Call Center Contacts for Bill-Related Calls	$4.0			
Reduction of Compensation/Claims for Meter Reading	$6.0			
Reduction of Load Research Costs	$8.5			
Reduction of Revenue Losses from Unoccupied Premises	$8.7			
Reduction of Handling Time for Calls regarding Power Quality Issues	<$0.1			
Reduction of Nested-Outage Restoration Time	$0.5			
Reduction of False Outage Dispatches	$1.3			
Increased Revenue Due to Reduced Outage Restoration Time	$1.2			
Reduction of Long-Term Outage Response Time	$1.7			
Reduction of Costs to Support Other Initiatives	$2.5			
Increased Energy Efficiency and Demand Response Participation that would Defer T&D System Upgrades		$10.1		
Increased Customer Utilization of eCommerce Channels		$0.7		$0.8
Avoided Capacity Costs Due to Increased Load Management Participation			$122.8	
Avoided Capacity Costs by Managing Unforeseen Market Changes in End-Use Devices			$101.4	
Decreased Customer Costs Due to Improved Outage Management			$35.8	
Decreased Electric Demand and Load that would Improve Environmental Conditions			$0.8	
Total Benefits	**$510.1**	**$10.8**	**$260.8**	**$0.8**

* Present value to 2007.

Business Case Assessment and Results

The examination of the cost factors identified and the benefits anticipated were factors taken into consideration in the development of an economic cost-benefit model. This model was constructed based on a deployment plan that would have the AMI fully installed over an eight-year implementation period beginning in 2007.

BENEFIT AND COST SUMMARY	Present Value* over 15 years ($millions)
Operational Benefits	$510.1
Future Operating Benefits	$10.8
Societal Benefits	$260.8
Future Societal Benefits	$0.8
Subtotal of Benefits	$782.5
Less: Costs	$712.8
Net Benefits	**$69.7**

* Present value to 2007.

Because the net of the costs and benefits is positive, the implementation of AMI is expected to be cost-effective.

PRE-DEPLOYMENT DEMONSTRATION PROJECTS

The Companies propose to undertake four pre-deployment demonstration projects ("pilots") at locations in Orange and Rockland, in Westchester, in Queens, and in the Bronx (including a portion of upper Manhattan). The pre-deployment projects described below are based on the Companies' "Optimal Solution" developed through research and analysis of the available technologies and their estimated costs. However, when vendor proposals or bids for each project are solicited and evaluated in accordance with the Companies' standard purchasing procedures, the pre-deployment projects may be modified to reflect information developed since the analysis reflected in this filing. Furthermore, selection of a technology or vendor for a pre-deployment project is no guarantee that the same technology or vendor will be selected for further deployment.

In general, these pre-deployment projects would have both common and unique objectives. Included among common objectives are both customer-focused goals and technology-focused goals. The unique goals would explore the performance of particular AMI technologies in specific topographies and distribution system characteristics. An outline of work associated with planning and carrying out these pilots is in the Appendix .

Common customer-focused goals

During the project planning phase, the Companies would develop a communications plan involving the education and awareness of key influencers. Governmental and other key representatives and organizations would be given presentations on what is planned as well as the goals of the pilots and tentative schedules for deployment. It is envisioned that employee education and coordination with other State and energy information agencies would be completed before any high-level mass-market communication is initiated. During these early phases, pilot design elements would be finalized using focus groups and other customer research.

Following the successful technology implementation, more traditional pilot implementation phases would be initiated. Customer usage data collected during these early technology implementation phases would provide important baseline information for program design selection and analysis. While the goal is to evaluate a cross-section of programs across geographic areas and technologies, the successes of the technology implementation phase may limit the scope of the program designs.

The mass-market program would test a continuum of pricing alternatives that require different levels of customer understanding of the market and various levels of responsibility and risk for customer energy decisions. Pricing alternatives would include incentives for load reductions, critical peak pricing to allow customers to respond to several price signals, and hourly pricing. Some would include an in-home technology (a thermostat or a device that would visually signal price changes). Others would be pricing-only programs and may offer variations of capacity and energy market pricing and perhaps bill presentation alternatives. While it may not be practical to test smart-home appliances because of the evolving standards for these devices, an important component would be testing various customer communication options for energy pricing, such as text messaging, Internet presentation, and email. Non-residential programs would test similar pricing options. In all cases, control groups would be identified for comparison.

Common technology-focused goals

For each of the respective technologies defined in the optimal case, the performance of key characteristics of the AMI would be verified. These include aspects such as:

- Equipment configuration and design – Actual performance data would be used to validate the vendors' coverage projections.
- Communication throughput – While the number of points may not be representative of the complete population, the size of these projects would permit a baseline of performance that can be used to extrapolate the latency and delays that may be realized once full-scale implementation occurs. For example, collecting hourly interval data as rapidly as possible through the system would allow some measure of communication throughput and capacity.
- Program process and logistics – These projects are expected to reveal many nuances related to timing, equipment availability, and process development that would need to be refined or optimized for full-scale deployment.
- AMI data collection and information integration – While many vendors of

MDMS claim experience with different AMI vendor systems, these systems typically provide front-end aggregation for only one or two AMI systems in parallel. Since the Companies' proposal involves several AMI systems, the selected MDMS's ability to successfully integrate all these in a uniform manner into a common platform would need to be demonstrated.

- Back-office system integration – Orange and Rockland and Con Edison have different customer information and record systems for billing and other customer processes. The design and integration of the common MDMS is pivotal to the realization of the projected AMI benefits across the Companies. The demonstration would be used to establish, test, and validate these links prior to broader deployment.
- Cost/performance trade-off evaluation – The balance between costs of infrastructure and delivered performance would be examined to more accurately project the actual costs of implementing, integrating, and operating an AMI system. The results of this effort would be used to refine the cost/benefit projections made in the initial case.

Area-Specific Demonstrations

Westchester – This project would include approximately 300,000 electric and gas end-points, which will have been deployed by the end of 2007 as part of the existing AMR program in the areas of Peekskill and Rye, and would use the Fixed RF Network "virtual" AMI arrangement.

Key performance measurement objectives would include the verification of migration of the Mobile AMR configuration to stationary fixed network "pole-top" data collectors. Of particular interest would be the validation of the method used to calculate the number of collectors required to adequately serve the meters selected for test. Another aspect of the demonstration would be the parameters that define the WAN connections and the suitability of wireless data services from existing cellular providers. This area is being populated with AMR modules that are expected to have the capacity to report interval data. Therefore, various business and technology processes associated with managing a large number of interval meter reads in a fixed network and the use of interval data information for billing and customer service would be evaluated.

Queens – This project would include installation or retrofit of approximately 100,000 electric and gas end-points, which would be deployed after a detailed project planning phase. This area would use an RF-mesh network configuration.

Key performance measurement objectives would include the verification of the communication capability of RF mesh in medium-density indoor meter locations in a network distribution system. Of particular interest would be the determination of the system response to a large number of units reporting simultaneously to simulate a large-scale power outage notification event. How the system handles the simultaneous delivery of a large number of messages would allow Con Edison to model a throughput profile. As part of this process the number of “take-out points” would be validated. Additionally, the balance between the number of infrastructure elements needed and the Companies’ tolerance for data latency would be evaluated. Checkpoints during this project would be used to measure the performance and efficacy of the solution as each group of approximately 10,000 meter points is installed. The decisions made at these checkpoints would determine any potential changes to the deployment schedule or the choice of technology. Likewise, the experiences gained during this stage would form a deployment model that would be applied in the deployment plans for the other RF-mesh project areas. Another aspect of the demonstration would be the exploration and evaluation of a large number of potential WAN providers. The proposed metropolitan WiFi system may be available for use during this project. Customers would be selected in the Long Island City network.

Southern Bronx/Upper Manhattan – This project would include installation or retrofit of approximately 100,000 electric and gas end-points, which would be deployed following a detailed project planning phase. This area would use an RF P2P system.

This area was chosen specifically to test the range and in-building penetration capability of this system without incurring the cost of siting a radio tower structure in Manhattan. Key performance measurement objectives would include the verification of the communication capability of this technology in indoor meter locations of high density, where challenges include subterranean and high-rise meter locations. Areas of interest to be demonstrated with this system would include defining the maximum coverage achievable in areas where large buildings may create RF shadowing effects. Another aspect of the demonstration would be the exploration and evaluation of a large number of potential WAN providers including a possible metropolitan WiFi system. Customers would be selected in the Southern Bronx and the upper Manhattan distribution network.

In a manner similar to the RF-mesh pilot described above, checkpoints would be established when each group of approximately 10,000 points is installed. Con Edison would use the information derived to determine any potential changes to the deployment schedule or choice of technology.

Eastern Division of Orange and Rockland – This project would include installation or retrofit of approximately 5,000 electric and gas end-points, which would be deployed after a detailed project-planning phase. This area would use an RF P2P system.

This area was chosen specifically to complement the plan to build the new Snake Hill substation and to support Orange and Rockland's plans to implement a "smart grid" for one radial distribution loop. Existing Orange and Rockland-owned towers in Pomona and Spring Valley would be used to locate the data collection equipment. Key measurement objectives would include verifying the radio performance in low-lying areas bounded by the Hudson River, where gaps exist with traditional radio technologies. The meter population is a moderately suburban area where meters are predominately located outdoors. Customers would be selected in the communities of Valley Cottage and Nyack.

Western Division of Orange and Rockland – This project would include installation or retrofit of approximately 5,000 electric and gas end-points, which would be deployed after a detailed project-planning phase. This area would use an RF P2P system.

This area was chosen specifically to test the range of the system in a very rural, sparsely populated area. Existing Orange and Rockland-owned towers in Greenville and Middletown would be used to locate the data collection equipment. Key measurement objectives would include verifying the radio performance in rolling hills where gaps also exist with traditional radio technologies. Customers would be selected in the communities of Unionville and Westtown.

COST RECOVERY

The Companies propose to begin recovery of all AMI and AMI-related costs contemporaneously with the initiation of the demonstration projects and implementation. The costs would include carrying charges on all capital investments associated with the AMI described in this proposal, other than the level of investments contemplated in and reconciled under the Con Edison Electric Rate Plan, including the pre-deployment demonstration projects, to the extent not addressed in utility rate case orders for Con Edison and Orange and Rockland, and all incremental O&M expenses incurred directly and indirectly in the implementation and operation of the AMI net of operational savings not yet accounted for in base rates. These costs would be recovered from all electric and gas customers. Until such time as these costs can be placed in base rates, the costs would be recovered through surcharges reset annually. Con Edison and Orange and Rockland would each make an annual filing for carrying charges and expenses not already recovered through base rates and reconciling the prior year's over- or under-collection. Because rates may be developed based on load information from the pre-deployment demonstration projects and other load research, the Companies should be permitted to recover lost electric and gas delivery revenues associated with customer participation in pilot rate programs that encourage reduction in customer usage. In addition, the Companies should be made revenue neutral for lost revenues during any transitional rate period.

FINDINGS

1) A full-scale AMI system for the Companies can be economically justified based on internal operational benefits and benefits that accrue to external stakeholders.

Total estimated investment required for the optimal case is $712.8 million. The projected internal operating benefits are $510.1 million over a 15-year investment period; the future benefits, most of which would accrue to external stakeholders or have less certainty of being achievable by the Companies, are projected to be $272.4 million over a 15-year life.

2) AMI systems could provide additional information about power outage conditions and could also improve the accuracy and timeliness of reporting these conditions.

AMI systems under consideration could provide various levels of outage and restoration functionality, though no single AMI system reviewed can receive simultaneous outage reports from every affected meter during a large-scale event. Even with today's limited reporting capability from these AMI systems, AMI outage-related functionality could give the Companies greater information regarding the extent of outage conditions.

3) AMI systems could provide a means to meet most of the Companies' operational needs and form a platform to provide additional future services.

AMI can satisfy most of the Companies' near-term operational needs, including:

- Reduction of O&M expenses for meter reading and field services labor, and
- Improvement in outage monitoring and reporting capabilities.

Some of the functionalities that would be enabled by AMI are:

- Ability to provide pricing options, based on time of day or hourly pricing structures,
- More direct load management or load control programs, and
- Ability to remotely upgrade AMI meters or device components, thus potentially eliminating the need to make costly field replacements or upgrades.

4) Because no single AMI communications technology can provide an economic or performance "best fit" for the Companies' combined service territories, several technologies are likely to be required and need to be evaluated through pre-deployment projects.

5) An MDMS is an essential component of an AMI system and is required to facilitate data accessibility and full benefit realization.

6) Available technology solutions could complement Con Edison's current AMR efforts, thus leveraging existing infrastructure investment plans.

CONCLUSION

Based on the positive business case laid out above, the Companies respectfully request that the Commission approve as expeditiously as practicable their proposals for AMI in their service territories and the cost recovery methodology for the Companies' costs, as described herein.

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Respectfully submitted,
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Appendix

Moving Forward with AMI

The Companies propose to

1) Conduct a series of pre-deployment demonstrations, as described above, with checkpoints during the implementation to:

   - Validate the cost and performance of AMI,
   - Verify the projected benefits,
   - Test consumer response to energy pricing and presentment options,
   - Evaluate customer response to system or network requirements for load reduction,
   - Explore program offerings to extend information to ESCOs and to customers, and
   - Examine the potential use of a metropolitan wireless system if and when it is available.

   The first part of this effort would be a planning phase. This would include:

   - Technology planning to select the location of communications equipment based on appropriate studies encompassing
     - o Customer types
     - o Communications issues
     - o Meter locations (indoors, subterranean, etc.)
     - o Meter density
   - Offer planning to determine the type of tariff designs, including time-differentiated programs, that might be considered, and
   - Marketing program design related to customer participation and education.

The second phase, which would overlap the first, would be the planning for deploying equipment for the pre-deployment demonstrations. During this stage, key vendor issues would include:

- Performance design and verification testing
- Test procedures
- Installation methodologies
- WAN Communications design
- Systems-level information design and integration
- Key Success Factors

The next stage would involve system readiness testing to ensure that the AMI System is functioning according to the design.

As the technology and economics are examined to validate the assumptions made and the Companies' deployment plans refined, the Companies would evaluate expansion of the deployment in reasonable stages to cover their entire service territories.

Except for the Westchester demonstration, the Companies anticipate the planning stage for the pre-deployment demonstration projects to take approximately 12 months and the initial deployment to occur over the subsequent 12-month period. Prior to installation, the Companies would engage in customer outreach and public education.

Because the effort in Westchester is aligned with the AMR efforts already underway in this area, Con Edison would commence the deployment of the fixed network infrastructure as soon as feasible, leveraging the meter installation work in progress.

2) Continually review the efficacy of their AMI approach through targeted actions, such as staying current with emerging vendor solutions and technologies and taking an active position

in standards-setting bodies and initiatives.

3) Monitor developments in emerging “behind-the-meter” communications technologies that would enable customers to understand the relationship between price and demand and their potential compatibility with the Companies’ AMI approach.

4) Update communications choices based on an evaluation of the suitability of future wide-area network communications options.