Niagara Mohawk Power Corporation
d/b/a National Grid

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION FOR ELECTRIC AND GAS SERVICE

Testimony and Exhibits of:

Advanced Metering Infrastructure Panel (Redacted)
Outdoor Lighting Panel

Book 9

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Submitted to:
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Submitted by:
Niagara Mohawk Power Corporation

nationalgrid

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Advanced Metering Infrastructure Panel

Dated: April 28, 2017

Testimony of the Advanced Metering Infrastructure Panel

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I. Introduction and Qualifications

Q. Please introduce the members of the Advanced Metering Infrastructure ("AMI") Panel.

A. The Panel consists of John O. Leana, James M. Molloy, and Pamela I. Echenique.

Q. Mr. Leana, please state your name and business address.

A. My name is John O. Leana. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc., a subsidiary of National Grid USA ("National Grid"), and currently hold the position of Director, Performance and Strategy New York. My responsibilities include supporting the New York Jurisdictional President on business strategy and energy policy issues, including activities in the New York Public Service Commission's (the "Commission") Reforming the Energy Vision ("REV") proceeding. I am currently responsible for leading the development of Niagara Mohawk Power Corporation d/b/a National Grid's ("Niagara Mohawk" or the "Company") AMI program and representing the Company on the Joint Utility Distributed System Platform Provider implementation activities.

Q. Please describe your educational and business experience.

A. I received a Bachelor of Science in Electrical Engineering from Clarkson University in 1988 and a Master in Electric Engineering from that same institution in 1989. In 1998, I received a Master of Business Administration from Oswego State University. I joined National Grid in 1989 and have held various positions of increasing responsibility in the areas of Transmission Planning, Corporate Planning, Finance, Credit and Collections, Meter Data Services, Merger/Restructuring, and Executive Support. I assumed my current role in April 2012.

Q. Have you previously testified before the Commission?

A. Yes. I have previously testified before the Commission.

Q. Mr. Molloy, please state your name and business address.

A. My name is James M. Molloy. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc., and currently hold the position of Director of Revenue Requirements for New York.

Q. Please describe your educational and business experience.

A. In 1992, I graduated from Catholic University with a Bachelor of Arts in Accounting. In 1994, I received a Master in Business Administration with a concentration in Finance from the William E. Simon Graduate School of Business Administration at the University of Rochester. I joined National Grid in 1995 and have held various positions of increasing responsibility in the areas of Rate Design and Pricing, Regulatory Accounting, and Revenue Requirements. I assumed my current role in 2011.

Q. Have you previously testified before the Commission?

A. Yes. I have testified numerous times before the Commission. Most recently, I testified on behalf of KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") and The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") in Cases 16-G-0058 and 16-G-0059 (collectively, the "2016 KEDLI and KEDNY Rate Cases"). I also testified on behalf of Niagara Mohawk in Case 10-E-0050 (the "2010 Electric Rate

Case") and Cases 12-E-0201 and 12-G-0202 (the "2012 NMPC Rate Case").

Q. Ms. Echenique, please state your name and business address.

A. My name is Pamela I. Echenique. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc., and currently hold the position of Director of New York Pricing. I am responsible for supervising the study, analysis, and design of delivery service rates, rate contracts, surcharge adjustment factors, riders, and terms and condition of service for Niagara Mohawk, KEDNY, and KEDLI.

Q. Please describe your educational and business experience.

A. I received a Bachelor of Science in Accounting from Syracuse University in 1992 and a Master of Business Administration from Le Moyne College in 1996. I joined National Grid in 1989 and have held various positions of increasing responsibility in the areas of Regulation and Pricing and Finance. I assumed my current position in 2014.

Q. Have you previously testified before the Commission?

A. Yes. I have testified numerous times before the Commission. Most recently, I testified in the 2016 KEDLI and KEDNY Rate Cases. I also testified on behalf of Niagara Mohawk in the 2010 Electric Rate Case and the 2012 NMPC Rate Case.

II. Purpose of Testimony

Q. What is the purpose of the Panel's testimony?

A. The Panel discusses the Company's proposal to deploy electric AMI meters and AMI-compatible encoder receiver transmitters ("ERTs") for its gas meters. Specifically, the Panel will explain why AMI is necessary to modernize the Company's electric and gas systems and advance the Commission's objectives set forth in the REV proceeding. To that end, the Panel presents a detailed business case and benefits-cost analysis ("BCA") that demonstrates the viability of AMI and ERT deployment across the Company's service territory. The Panel also describes the customer, societal, safety, and operational benefits of AMI. In addition, the Panel discusses the Company's proposed implementation schedule, customer engagement and stakeholder outreach plan, and metrics to measure the success of AMI deployment. Finally, the Panel describes new products and offerings made possible by the Company's AMI investment that will empower customers by providing enhanced energy consumption data and more choices for managing their energy usage.

The information concerning projected AMI costs has been provided to the Revenue Requirements Panel and was used to develop Niagara Mohawk's proposed electric and gas revenue requirements.

Q. Does the Panel sponsor any exhibits as part of its testimony?

A. Yes. The Panel sponsors the following exhibits that were prepared or compiled under our direction and supervision:

(i) Exhibit ___ (AMI-1) is the AMI business case and BCA that was included in the Company's Distributed System Implementation Plan ("DSIP") filed with the Commission on June 30, 2016 and subsequently corrected on July 1, 2016; and

(ii) Exhibit ___ (AMI-2) is the updated AMI business case and BCA, dated April 28, 2017.

(iii) Exhibit ___ (AMI-3) is a schedule of the AMI costs and benefits.

III. <u>AMI Program Overview</u>

Q. Please summarize the Company's AMI proposal.

A. The Company's proposal includes four main components: (i) AMI meters for electric customers and AMI-compatible gas ERTs for gas customers (the ERT is the module that transmits data from the meter); (ii) a telecommunications network to support AMI communication; (iii) back-office information technology systems to manage the two-way communications enabled by AMI, store the electric and gas consumption data, and support billing and customer service activities; and (iv) products and services made possible through the investment in AMI that will empower customers to take meaningful actions to conserve energy and manage their energy bills.

Niagara Mohawk will install approximately 1,690,000 electric AMI meters and approximately 640,000 gas ERTs across its service territory over a four year period, with deployment scheduled to begin in Data Year 2 (the 12 month period ending March 31, 2021). The proposed deployment period aligns closely with the planned replacement cycle of electric AMR meters and gas ERTs. As the AMI program is implemented, the Company anticipates future efficiencies and cost reductions (*e.g.*, meter reading expense), performance improvements, and other benefits for customers.

Q. Is the Company's AMI proposal supported by a business case?

A. Yes. Niagara Mohawk filed its DSIP on June 30, 2016, with a subsequent correction filed on July 1, 2016. The DSIP set forth a plan for investments needed to modernize the Company's system and enhance Distributed System Platform ("DSP") capabilities. In the DSIP, the Company identified AMI as a foundational component of its grid modernization effort that will change the energy future of the Company and its customers.

The DSIP included an AMI business case that described and compared alternative AMI deployment options and, based on the results of the BCA, proposed full deployment as the recommended approach (Exhibit ___ (AMI-1)). A more detailed and updated business case for full deployment has been developed for this filing and is included in Exhibit ___ (AMI-2) (the "Business Case"). The Business Case describes, among other things, the customer and other benefits of AMI, the plan and schedule for deployment, the end-to-end technologies and systems necessary to implement and operate the AMI system and a description of their functionality, the program implementation support required for effective management of the AMI program, illustrative rate design structures, customer rate impact analyses, and the BCA.

Q. What meter reading technology does Niagara Mohawk currently utilize?

A. Niagara Mohawk utilizes an automated meter reading ("AMR") system. Meters are read on a monthly basis by a fleet of Company vehicles that retrieve consumption data from the AMR meter through the use of radio frequency technology.

The electric AMR meter is a solid state electronic device with integrated communication capability that can measure cumulative energy usage and active and reactive peak demand. In contrast, gas meters are equipped with an external ERT module that records and transmits the gas consumption data measured by the meter.

Q. Please describe the proposed electric AMI meter technology.

A. The electric AMI meter or "smart meter" is an electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information using two-way telecommunications infrastructure. The device interfaces with a utility's back-office systems using either a cellular radio or a mesh network, and the utility's private backhaul network. In addition to interval measurement, the AMI metering system support numerous other functionalities and service enhancements, including: real-time query of usage data; tamper detection; more reliable measurement; power outage status; voltage status; remote connect and disconnect; remote diagnostics; remote firmware upgrades; and home area network communications.

Q. Please explain why the gas ERT is being upgraded as part of the AMI proposal.

A. Replacement of the ERT will allow the gas meter to communicate with the electric AMI meter, enabling near real-time meter readings (instead of monthly) without the need to dispatch a Company vehicle. This will create efficiencies that have been reflected in the BCA and will ultimately benefit customers. Additionally, the upgraded gas ERT will enable future functionality such as the ability to communicate with ancillary gas safety devices (*e.g.*, methane detectors and remote disconnect valves). To accommodate the new ERT, the Company estimates the need to replace approximately 10 percent of gas meters during deployment.

Q. Why is Niagara Mohawk proposing to implement AMI?

A. Niagara Mohawk is implementing AMI to provide its customers with the knowledge and tools needed to better inform their energy decisions and manage their energy costs. At the same time, AMI will modernize the

Company's system, enabling improved planning and operations, and the integration of increasing levels of distributed energy resources ("DER") to support a cleaner, more resilient and efficient system, consistent with the Commission's REV objectives and New York State's clean energy goals. AMI will also provide the infrastructure and capabilities necessary to support the development and integration of distribution markets, in furtherance of the Company's role as the DSP provider.

AMI is a proven technology with 65 million smart meters installed covering 50 percent or more of U.S. households today.[1] Meter deployments are expected to reach 90 million households by 2020. Full AMI deployment offers many benefits to Niagara Mohawk and its customers. The benefits are discussed in detail in the Business Case (Exhibit ___ (AMI-2)) and summarized in the next section.

Q. Are other utilities in New York State proposing to implement AMI systems?

A. Yes. In the Supplemental DSIP filed by the Joint Utilities on November 1, 2016 in Case 16-M-0411, all but one of the Joint Utilities indicated that

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[1] IEI Report, Electric Company Smart Meter Deployments: Foundation for A Smart Grid (issued October 2016)

full AMI deployment was a foundational component of their respective DSPs. Recently, the Commission authorized Consolidated Edison to implement AMI and is currently considering petitions filed by New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, and Orange and Rockland Utilities, Inc.

The timing of the Company's AMI proposal is driven by similar business considerations to those of the other New York State utilities, and will provide Niagara Mohawk's customers with access to the same AMI benefits being proposed for other customers in the State. The timing also permits the Company to benefit from lessons learned from these utilities as well as the Company's Clifton Park demonstration project, which is described by the Electric Customer Panel.

IV. <u>AMI Benefits</u>

Q. Please discuss the benefits that AMI will provide customers.

A. The Company expects AMI to provide substantial customer benefits including:

- *Enhanced Customer Energy Management and Reduced Consumption:* When AMI meters have been deployed and the associated back-office infrastructure is in place, customers will have access to their usage data in near real-time, with granularity at sub-hourly reading intervals. Under the Company's AMI program, electric customers will have access to their raw usage data within four hours after an interval. Gas customers will have access to their raw usage information within eight hours. In both cases, customers will have bill quality data within approximately 24 hours of the end of a given interval. The frequency of the readings combined with the granularity of the data will enable customers to take control of their energy usage through energy efficiency and demand response programs. AMI will also allow customers to monitor their energy consumption through the use of products discussed later in this testimony (*e.g.*, Green Button Connect My Data and the Energy Management Portal), which will allow customers to better manage their energy bills.

- *Third-Party Programs and Offerings:* AMI will facilitate the creation of a distribution marketplace as well as access to the wholesale power market. Interval data collected by AMI can be shared between customers and authorized third-parties. This allows for the development of new, innovative third-party products and offerings that can be targeted to customers' individual energy needs. The interval data will also support participation in the New York Independent System Operator ("NYISO") hourly wholesale markets. Expanding customer choice is expected to increase customer awareness and participation in the energy marketplace, resulting in potential cost savings and reductions in overall energy consumption.

- *Innovative Rate Design Options:* AMI lays the foundation for innovative rate design structures that can reward customers for optimizing their energy usage (*e.g.*, time of use rates and critical peak pricing programs). It also holds potential to support "Smart Home" rates in the future. Innovative rate design options are discussed in the Business Case and summarized later in the Panel's testimony.
- *Enablement of Smart Home Devices:* AMI will enable customers to manage their energy consumption through use of smart home devices such as thermostats, water heaters, and other appliances that can be integrated with AMI. Home energy management systems will be able to send and receive secure communications from the Company or third-parties. Based on customers' preferences, the system can automatically adjust energy usage with pricing signals and calls for curtailment.
- *Outage Management:* AMI has the ability to report a customer outage in near real-time, without the need to rely on notification from a customer or substation monitoring. Earlier notification of an outage may speed restoration of service. The functionality also allows the

Company to send a signal to AMI meters to identify areas that still require restoration and confirm when all outages have been restored. The Company expects to explore and develop these new capabilities once meters have been fully deployed.

- *Customer Service Enhancements*: AMI data can be used by the Company's call center representatives to enhance customer interactions. For example, AMI will allow call center representatives to send a signal to the meter to determine voltage levels or if an outage is due to customer-owned equipment; will allow for real-time reconnects of electric meters; can provide historic information about prior outages and voltages; and can provide for additional rate offerings and options for customers seeking flexibility for their energy management needs.

Q. Please discuss the operational benefits that AMI will provide to the Company.

A. AMI will provide a number of important operational benefits that will enhance the safety, reliability, and efficiency of the Company's electric and gas networks, such as:

- *Grid Planning and Load Management:* The greater granularity and frequency of energy consumption data provided by AMI will enhance the Company's ability to analyze customer usage patterns for grid planning and load management purposes. In particular, data from AMI meters will better enable the Company to integrate DER into the distribution system to support non-wires alternatives, hosting capacity, and demand response programs.

- *Remote Connect and Disconnect Abilities*: If electric power has been disconnected, AMI will enable power to be restored remotely, without the need to dispatch field personnel. Likewise, electric power can be shut off remotely if requested by the customer (*e.g.*, because they are moving) or for non-payment of service, in accordance with the requirements of the New York Home Energy Fair Practice Act.
- *Volt-Var Optimization/Conservation Voltage Reduction ("VVO/CVR") Program Enhancements*: The VVO/CVR Program, which is described in the Electric Infrastructure and Operations Panel's testimony, involves the deployment of voltage control devices to optimize the performance of the distribution system. The more granular and frequent data from AMI meters enhances the effectiveness of this program. In particular, a subset of AMI meters can act as end-of-line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics. More granular metering information can also define more precise load models of

individual circuits with adjustments for time of day and year or temperature correlation.

- *Reduced Meter Investigations:* AMI can provide auto and on-demand meter reads and diagnostics to alert and inform the Company about anomalous situations (*e.g.*, zero readings). In turn, this functionality should reduce the number of Company visits to the meter for manual service investigations.
- *Outage Reporting:* AMI's ability to provide the Company with near real-time power outage notification allows system operators to assess outage characteristics more quickly, provides more extensive situational awareness, and enables the Company to take steps to restore power more efficiently. Further, once power is restored, AMI meters can be signaled to assess whether the entire outage is restored or if additional work needs to be done to restore nested outages (*i.e.*, a service interruption that remains for a particular premise or area after service to the main lines of a circuit have been restored). The Company expects to explore and develop these new capabilities in the future once meters have been fully deployed.
- *Theft Detection*: AMI technology combines meter alerts and greater frequency of readings with sophisticated algorithms to ensure energy consumption is accurate. These algorithms can detect usage that

bypasses the meter and will alert the Company to possible theft situations. This will allow for more timely investigations that should ultimately minimize theft-of-service costs.

Q. What other benefits will AMI provide?

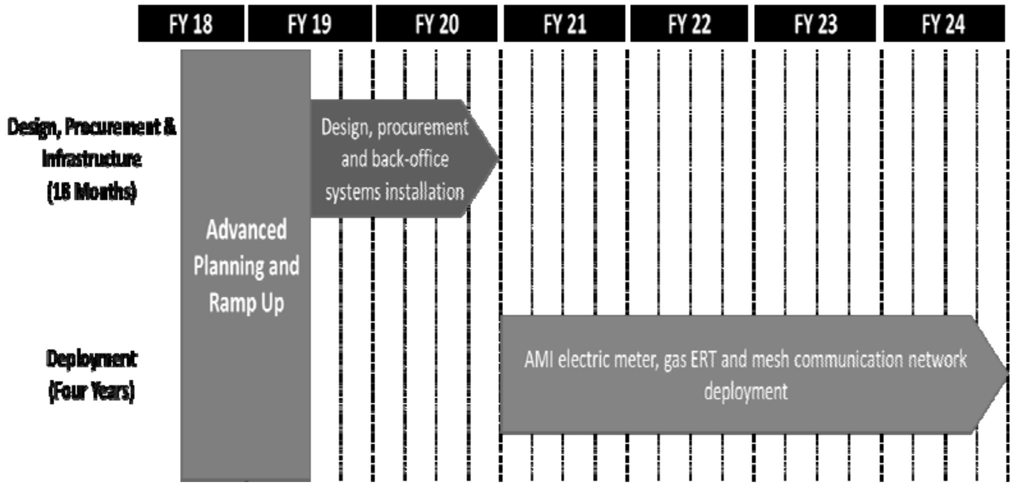
A. In addition to customer and operational benefits, AMI will produce societal benefits through the reduction of greenhouse gas emissions. Reductions will occur as a result of energy conservation enabled by AMI, including enhanced access to usage information and usage alerts, education, and pricing programs. Greenhouse gas emissions will also be reduced by eliminating the need for vehicle trips to read meters, connect and disconnect service, and investigate service anomalies.

V. Implementation Plan

Q. Please describe the Company's proposed implementation plan.

A. The Company is proposing a phased AMI implementation over a five-and-a-half year period as illustrated in Figure 1.

Figure 1 – AMI Implementation Plan



Phase 1: Over the 18 month period beginning in the middle of the Rate Year (the 12 month period ending March 31, 2019) and extending through Data Year 1 (the 12 month period ending March 31, 2020), the Company will complete the design, procurement, and back-office systems installation phase of the project. During this phase, the Company will staff a project management organization and conduct a formal design and procurement process that will involve the development of: (i) a detailed customer engagement and stakeholder outreach plan (discussed in more detail below); (ii) system requirements, including integration, process design, and change management, along with an AMI-specific cyber security plan: and (iii) a meter deployment plan. The Company will use

its procurement process to select software, equipment, and support vendors for the program.

The design and procurement process will be followed by the installation of back-office information technology systems and communications infrastructure. This will involve building and testing the end-to-end solutions, development of procedures and training materials, organization implementation, including training of field and office personnel, development of communication materials, and initiation of meter deployment communications.

Phase 2: In Data Year 2, the Company will begin a four year deployment of AMI electric meters, gas ERTs, and the communication network that is estimated to be completed in fiscal year ("FY") 2024. For purposes of the Business Case and the revenue requirements, the Company estimated that approximately 20 percent of electric meters and 20 percent of gas ERTs would be installed in Data Year 2, followed by 30 percent in each of FYs 2022 and 2023, and 20 percent in FY 2024. Actual deployment could vary from these assumptions based on considerations such as meter density and population and benefit realization.

The work to be conducted in each phase is discussed in more detail in the Business Case (Exhibit ___ (AMI-2)).

Q. What are the benefits of the Company's phased implementation strategy?

A. The phased approach has many strategic benefits. It allows time for the Company to issue requests for proposals and engage in competitive negotiations with vendors to obtain the best prices for customers. The schedule also allows the Company to develop the processes and organizational capabilities to ensure the effective management and delivery of the AMI program. In addition, the schedule enables the Company to engage stakeholders to develop a comprehensive customer engagement plan that will ensure customers have the information needed to access the benefits provided by AMI before meters are installed.

Because meters will not be installed until Data Year 2, the approach also allows the Company to learn from the current Clifton Park Demand Reduction Demonstration Project and other utility projects and develop innovative rate design proposals that would further access the benefits of AMI.

Q. How will the AMI proposal benefit from the Clifton Park Demand Reduction Demonstration Project?

A. As part of the Clifton Park Demand Reduction Demonstration Project, the Company has begun deploying AMI meters to approximately 14,400 residential electric customers in the Town of Clifton Park. Approximately 86 percent of these accounts are also Niagara Mohawk residential natural gas customers and will receive new gas ERTs as well. The demonstration project will serve as a test bed and learning environment that will inform the development and delivery of the broader AMI technical solution and customer engagement program.

From a technical standpoint, the Clifton Park Demand Reduction Demonstration Project will test smart meters that utilize cellular communication to connect to the Company's back-office systems. This technology will be utilized in rural areas as part of the broader AMI program where customer density is insufficient to support a mesh network design. The demonstration project will also test customer engagement in response to energy information by examining customer awareness, interest, comfort, knowledge, and satisfaction with project offerings through customer surveys. The main element of the program, behavioral demand reduction or peak time rewards, will incentivize customers to reduce their load during peak demand to earn points that can be redeemed for gift cards. The Company will seek to measure the impact specific engagement campaign events have on adoption rates for time variant pricing and DER and incorporate learnings in the larger AMI program.

Q. Does the implementation plan reflect changes from the plan proposed in the Company's DSIP filing?

A. Yes. In preparing this rate filing, the Company was mindful of steps it could take to deliver benefits to customers sooner. Therefore, the proposed meter deployment schedule has been shortened from five years, as originally set forth in the Company's DSIP, to four years.

Q. Did the Company consider options aside from full AMI deployment?

A. Yes. In the initial AMI business plan contained in the Company's DSIP, Niagara Mohawk evaluated multiple deployment strategies (Exhibit ___ (AMI-1). The strategies included full AMI deployment, targeted deployment in only urban areas (approximately 40 percent of electric meters and gas ERTs), and deployment to customers who opt-in to the program (approximately 10 percent of electric meters and gas ERTs). The analysis revealed that only full deployment would provide the customer, operational, and societal benefits of AMI and meet the Company and customers' needs in a cost effective manner.

Moreover, the alternatives to full deployment do not provide the broader planning, operational, and market capabilities necessary to achieve the State's energy policy objectives of integrating DER into energy networks. In addition, the targeted urban alternative would result in the benefits of AMI being provided to some but not all customers. It would be inequitable, for example, to provide customers in urban areas with access to the many benefits of AMI such as access to information that could help them better manage their energy bills and improve service but not provide these same benefits to customers in rural areas.

Q. What precautions will the Company take to ensure the security of data provided through AMI?

A. The Company understands that there are increasing cyber security risks in an evolving technology landscape. As part of Phase 1 of the implementation plan, the Company will develop a comprehensive AMI-specific cyber security plan. The Company has developed an overall framework, including a range of cyber security capability investments, to address the new challenges introduced by system modernization, including

AMI. At a high level, the AMI-specific plan will ensure that proper end-to-end security controls are incorporated into all aspects of design, implementation, and deployment of AMI technology. These security controls will ensure that all AMI devices, communications infrastructure, and back-office systems, along with user portals and other critical infrastructure, are fully secured and monitored. Moreover, the plan will also ensure that any data transmitted across this network is properly encrypted using nationally recognized standards and protocols.

VI. Customer Engagement and Stakeholder Outreach and Metrics

Q. Please discuss the Company's plan for customer engagement and stakeholder outreach.

A. The Company recognizes the importance of pairing AMI with proactive customer and market engagement initiatives. Therefore, the Company proposes to develop a detailed customer engagement plan, with stakeholder input, during Phase 1 of the AMI program and to file the plan with the Commission in Data Year 1. The plan will be guided by the staged approach the Company has implemented and gained experience with as part of its Clifton Park demonstration project and its sister affiliate's experience with a smart meter pilot in Worcester, Massachusetts. Specifically, the stages will include:

Stage 1 - Deployment: During the deployment stage, the Company will initiate a smart meter campaign to inform the public of the benefits associated with AMI. The Company will conduct proactive customer engagement across various forums to set expectations and mitigate potential concerns about AMI.

Stage 2 - Steady State: The objective of this stage is to increase customer satisfaction by providing them with access to the enhanced data provided by AMI. To attain this goal, the Company will need to be proactive and leverage engagement technology solutions such as the Energy Management Portal and Green Button Connect My Data initiatives described below. Increased accessibility to data and self-service portals will allow customers to become more autonomous and have greater levels of satisfaction with AMI.

Stage 3 - Program Education/Enrollment: The goal of this stage is to educate customers on the opportunities and benefits associated with participation in utility or third-party services and programs to further unlock the benefits of AMI. Similar to Stage 2, a proactive approach supported by technology solutions such as the E-Commerce Platform (described below) is required. The increased knowledge of opportunities coupled with customer involvement aims to increase customer satisfaction by providing them with options to manage their energy costs.

This three-stage plan will utilize a multi-channel, multimedia campaign that integrates social media to inform and educate energy consumers.

Q. How will the Company address situations where customers do not want an AMI meter?

A. Customers will be informed via mail sufficiently in advance of AMI meter installation of their ability and the process to opt-out of the AMI program. Processes and resources will be in place to support customers who are considering or have decided to opt-out. Electric customers who opt-out of the program will have an AMI meter installed with the communication capability deactivated. Gas customers who opt-out will not have the gas ERT installed. Customers who opt-out of the program will have their meters read manually on a monthly basis and will be subject to the terms and conditions specified in the Company's opt-out meter reading tariff, which will include a monthly meter reading fee.

Q. Is the Company proposing metrics to measure the success of the AMI program?

A. Yes. As described above there are numerous customer and operational benefits enabled by AMI. These benefits will start to be realized as meters are deployed and will continue to increase in future years as capabilities are leveraged by the Company and third-party market participants. As discussed in the Business Case, during the deployment phase of the AMI program the Company proposes to implement the following three metrics:

- AMI Program Progress – This measure will track the achievement of key program milestones such as the completion of the back-office systems, customer engagement solutions, and the number of meters installed.
- Customer Survey Measure - A customer survey will be developed and implemented to measure customer satisfaction with the meter installation process and the Company's planned customer engagement program. The survey will be administered on a rolling basis following meter deployment and customer engagement activities.
- Customer Engagement – This measure will track the number of customers who engage in energy management activities through the various customer engagement solutions described below (*i.e.*, the

Energy Management Portal and E-Commerce Platform). The measure will also measure enrollments in various AMI enabled programs such as demand response and time variant pricing.

The Company proposes to include these metrics in its customer engagement plan.

VII. <u>AMI Capital and Operation and Maintenance Expense</u>

Q. What costs are included in the revenue requirements for the AMI program?

A. For the electric business, the revenue requirement includes forecast capital and operation and maintenance ("O&M") expense, respectively, of $7.33 million and $2.29 million in the Rate Year, $13.76 million and $14.48 million in Data Year 1, and $67.01 million and $13.72 million in Data Year 2.

For the gas business, the revenue requirement includes forecast capital and O&M expense, respectively, of $2.72 million and $0.85 million in the Rate Year, $5.11 million and $5.25 million in Data Year 1, and $20.98 million and $4.77 million in Data Year 2.

The increase in capital costs in Data Year 2 reflects the start of meter deployment.

Q. Please summarize the cost components.

A. The major components of capital costs include: (i) meter equipment and installation (*i.e.*, AMI electric meters and gas ERTs); (ii) communication equipment and installation; (iii) Information Systems ("IS") platform and ongoing IS costs; and (iv) project management and ongoing business operations.

O&M expense include IS systems and integration costs that are projected to be provided under a software as a service arrangement, project management support, communications, customer engagement, and other costs necessary to implement the new system.

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A complete breakdown of the capital and O&M costs is contained in Exhibit ___ (AMI-3) and explained further in the Business Case (Exhibit ___ (AMI-2)).

Q. Please explain how the cost estimates were developed.

A. Cost estimates were developed with the support of Accenture Consulting ("Accenture") and rely on multiple sources, including vendor information, Accenture's experience and benchmarks, and the Company's experience. Equipment costs for meters, ERTs, and the telecommunication network are based on vendor information from the Company's demonstration project experiences and vendor partners. Other costs such as installation, project management, and customer engagement are based on Accenture and Company experience and generally assume internal sourcing. Information technology and cybersecurity costs were developed by the Company with the support of Accenture.

Q. How are costs allocated between Niagara Mohawk's electric and gas businesses?

A. Costs that are not common to both the electric and gas businesses, such as electric meters and gas ERTs, were directly assigned to the electric or gas businesses. Common costs that support both electric and gas were primarily allocated based on electric and gas customer counts. However, in a few areas, such as telecommunications costs, specific allocation methodologies were developed based on cost causation principles.

Q. Does the Company anticipate future cost reductions associated with the AMI program?

A. Yes. The Company anticipates future avoided O&M and capital costs will be realized through the proposed system-wide deployment of AMI. As set forth in the Business Case (Exhibit ___ (AMI-2)) and Exhibit ___ (AMI-3), the Company estimates potential O&M savings of $139.03 million and capital savings of $254.35 over a 20-year evaluation period on a net present value ("NPV") basis. The savings are estimated to result from a reduction in meter reading field operations, damage claims, and avoided AMR costs (*i.e.*, avoided capital and O&M expense associated with the existing AMR life-cycle replacement program).

These benefits will begin to be realized following the first year of meter deployment in Data Year 2 and are expected to increase in future years. However, reductions in commodity costs will begin to be realized in Data Year 2 and flow back to customers through mechanisms outside of base rates.

VIII. <u>BCA</u>

Q. Please describe the BCA and the approach taken to prepare the document.

A. Utilizing the Commission's BCA framework and the principles outlined in the Company's BCA Handbook, the Company conducted a data-driven analysis of the benefits and costs of the proposed AMI program. Exhibit ___ (AMI-2) contains the BCA.

Q. What benefits were evaluated and included in the scope of the BCA?

A. The benefits evaluated include: (i) avoided O&M costs; (ii) avoided AMR costs; (iii) customer benefits; and (iv) societal benefits. Customer and societal benefits include savings in generation capacity costs and energy costs through time variant pricing scenarios. For the BCA, the Company considered four different time variant pricing scenarios – an opt-in with both a low and a high savings estimate and an opt-out with both a low and a high savings estimate.

Q. Please summarize the results of the BCA.

A. The results of the BCA are positive and demonstrate that customers should realize significant benefits from the Company's AMI program. The BCA shows that Niagara Mohawk will invest approximately $608 million in capital and O&M costs over the 20 year Business Case evaluation period on an NPV basis. The AMI program is expected to yield corresponding benefits of between approximately $584 million (assuming the low savings estimate scenario) and $948 million (assuming the high savings estimate scenario), for net benefits in the range of ($24 million) and $340 million under the Societal Cost Test ("SCT"). It should be noted that the SCT does not consider benefits in the area of revenues such as reductions in lost revenue and bad debt expense.

The BCA results for the SCT, the Utility Cost Test ("UCT"), and the Rate Impact Measure ("RIM") for the four time variant pricing scenarios evaluated are set forth below in Table 1.

Table 1 – BCA Test Results

Pricing Scenarios	SCT	UCT	RIM
Opt-in/Low Savings	0.96	0.81	1.02
Opt-in/High Savings	1.05	0.90	1.14
Opt-out/Low Savings	1.20	1.06	1.34
Opt-out/High Savings	1.56	1.44	1.82

Under the Commission's BCA framework, the SCT is the primary measure of cost-effectiveness. The results demonstrate that the Company's AMI program meets the SCT for all but the opt-in/low savings pricing scenario. The RIM test results are positive across all scenarios, demonstrating the added value provided by the revenue benefits.

Q. Are there other potential cost reduction or benefit opportunities that were not considered in the BCA?

A. Yes. It may be possible for Niagara Mohawk to share a portion of the IS platform and ongoing costs with its affiliate companies should they implement AMI. In addition, there are a number of future benefits opportunities that have been identified such as outage management, street lighting, and gas safety applications that are described in further detail in Section 5.6 of the Business Case, but not included in the BCA.

IX. New Products and Services

Q. Please describe the technology solutions the Company is pursuing to enhance customer accessibility and functionality in connection with the AMI investment.

A. The Company is proposing to implement Green Button Connect My Data, an Energy Management Portal, and an E-Commerce Platform. The first two solutions focus on making AMI more interactive for customers while providing them with enhanced levels of information about their energy usage. The third solution connects customers with new product and service offerings.

Q. Please describe the Green Button Connect My Data initiative.

A. Green Button is an industry-led effort to provide utility customers with easy and secure access to their energy usage information. Niagara Mohawk has already implemented the Green Button Download My Data feature, which allows customers to download their usage data by clicking the Green Button on the Company's website. The proposed Green Button Connect My Data initiative expands the current functionality by allowing customers and the Company (at the customer's request) to share energy usage data directly with designated third-parties. This feature unlocks new participation opportunities for approved third-parties to help customers better understand their energy usage and take meaningful actions to manage their bills. Working with these providers, customers can obtain customized energy solutions for use in their homes and businesses to optimize their energy usage. The sharing process will be automated for ease of customer use and the data will be provided in a secure format, similar to the efforts of other New York utilities.

Q. Please describe the Energy Management Portal.

A. The Energy Management Portal is a web-based tool that will allow residential, commercial, and industrial customers to view their energy usage, including AMI meter interval data. This platform will allow customers to view billing quality data within 24 hours of the end of a given billing interval. The application will be available through the Company's existing webpage and will also be integrated with smartphone applications, allowing customers to access their data on the go and create customizable alerts notifying them of high use or events on the system. In addition to allowing customers to view their energy consumption in near real-time, the Energy Management Portal will allow customers to compare their usage and costs against certain variables such as weather, historic consumption at the same time and dates, and comparable customers' usage to understand factors that may be driving their energy use.

Armed with this information, customers can take action using the functionality that the Energy Management Portal provides. This could include shopping for energy saving products and services through the Company's proposed E-Commerce Platform, or enrolling in energy efficiency, demand response, and other pricing programs. In addition, customers can access the Energy Management Portal for energy savings programs and personalized energy tips and strategies to reduce their energy usage.

The costs of the Green Button Connect My Data and Energy Management Portal are included in the AMI program costs.

Q. Please describe the E-Commerce Platform.

A. The E-Commerce Platform is described in the testimony of the Electric and Gas Customer Panels.

X. Rate Design Options and Rate Impacts

Q. As part of the Business Case, did the Company (i) illustrate proposed rate design structures and (ii) conduct a customer rate impact analysis?

A. Yes. In the Business Case, the Company illustrated potential time of use and critical peak pricing rate designs. Actual rate designs used by the Company during AMI deployment could differ from these illustrations. Niagara Mohawk intends to leverage learnings from the Clifton Park Demonstration Project and work with parties in the Track Two Order (Case 14-M-0101) to inform future rate design offerings.

With respect to customer rate impacts, the analysis is set forth in Section 7 of the Business Case (Exhibit ___ (AMI-2).

XI. Conclusion

Q. Please summarize the Panel's testimony.

A. Niagara Mohawk considers AMI a foundational component of its grid modernization efforts. The Company evaluated multiple deployment scenarios and only full deployment met the Company and customers' needs in a cost effective manner. Implementation of AMI is estimated to generate net societal benefits of approximately $340 million (assuming the high savings estimate scenario). For these reasons, the Company believes AMI is a prudent and necessary investment that should be undertaken.

Q. Does this conclude the Panel's testimony?

A. Yes.

Exhibits of
AMI Panel

Index of Exhibits

Exhibit__ (AMI-1)	AMI business case and BCA included in the Company's Distributed System Implementation Plan ("DSIP")
Exhibit__ (AMI-2)	Updated AMI business case and BCA dated April 28, 2017
Exhibit__ (AMI-3)	Schedule of AMI costs and benefits

Exhibit __ (AMI-1)

AMI business case and BCA included in the Company's Distributed System Implementation Plan ("DSIP")

Appendix 3: AMF Business Case

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Electric and Gas

Advanced Metering Functionality

Business Case

for

Niagara Mohawk Power Corporation d/b/a National Grid

June 30, 2016

Table of Content

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1 EXECUTIVE SUMMARY

This section summarizes the full business case report that is captured in the following sections of this document.

1.1 The Potential of Advanced Meter Functionality

In response to an evolving regulatory and market landscape in New York State, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") has developed an Advanced Meter Functionality Business Case ("AMF Business Case"). The AMF Business Case demonstrates the viability of a full electric and gas smart meter technology deployment, as well as supporting infrastructure and systems. Such deployment builds the foundation to support fundamental change in the energy future of the Company's customers, the electric and gas distribution system and the State of New York. By investing in AMF, National Grid will be taking a key step toward achieving the "Reforming the Energy Vision" ("REV") objectives as adopted in the Public Service Commission's ("Commission") Order Adopting Regulatory Policy Framework and Implementation Plan[1] and to enabling the Company to assume the role of the Distributed System Platform Provider ("DSP"). These objectives include:

- Empowering greater customer control over energy usage through participation in demand response ("DR"), energy efficiency ("EE") programs, and pricing programs;
- Allowing granular electric and gas consumption data to be available to customers and approved third-party vendors in a timely and efficient basis;
- Providing customers access to a marketplace, and the ability to choose new and innovative energy solutions from third-party vendors; and
- Increasing electric grid reliability and resiliency.

In the broader context of the REV framework, AMF is a key component for building a robust, dynamic electric distribution grid, well positioned to integrate distributed energy resources ("DERs") as adoption accelerates. AMF provides the granular and spatial consumption and system information that supports and optimizes many of the planning, grid operations and market functions of the Distributed System Platform Provider ("DSP"). AMF can increase productivity and efficiency, allowing operations to restore outages faster and optimize grid performance, in combination with grid modernization investments. Further, AMF enables DSP planning functions such as demand modeling, load forecasting, and capital investment planning. Beyond the core data granularity and meter-reading-to-bill functions, AMF can act as a coordinated group of sensors stretching across National Grid's service territory. Combined with other capabilities envisioned in the DSIP, but outside the scope of the AMF Business Case, this ability can enhance the functionality of various systems and business units. An Advanced

[1] Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).

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Distribution Management System ("ADMS"), for instance, is enhanced by the grid of sensors, leveraging them to expand the situational awareness of grid operators, to more quickly identify and respond to outages. Additionally, with "grid optimization" AMF data is an enabler resulting in more accurate, more efficient outcomes for currently available capabilities such as voltage optimization and DER integration.

1.2 AMF Deployment Options

The AMF Business Case presents a comparative assessment of the benefits and costs of three AMF deployment options of different scale. They are described in Figure 1.

Option	Description
A	Full deployment of both electric Advanced Metering Infrastructure ("AMI") meters and gas Encoder Receiver Transmitters ("ERT") across National Grid's service territory.
B	Deployment of both electric AMI meters and gas ERTs across National Grid's service territory in high-density population areas (approximately 40% of total electric and gas meter points).
C	Deployment to any customers in National Grid's service territory who choose to opt-in (approximately 10% of total electric and gas meter points)

Figure 1: High-level descriptions of National Grid's deployment options

1.3 Common Systems and Functionalities across Deployment Options

While the deployment size may vary significantly from Option A to C, there are a number of common systems and functionalities that will be implemented no matter which option is chosen. These common AMF pieces include:

- **Energy Consumption Data Availability:** Electric customers will have access to their raw, not validated, edited and estimated ("VEE"), usage data within four hours after an interval. Gas customers will have access to this raw usage information within eight hours due to battery limitations. In both cases, customers will have bill quality data within approximately 24 hours of the end of a given interval. The Company expects to engage stakeholders further with respect to their real-time information access needs following the initial DSIP filing as well as in conjunction with the supplemental DSIP stakeholder engagement process.
- **Metering Back Office Systems:** The hardware and software that support metering functionality like the AMI Head-End, Meter Data Management System ("MDMS"), and Data Warehouse will be integrated into the back office systems.
- **Customer Service System**: The Customer Service System ("CSS") is a set of adaptable applications designed to manage customer-facing activities. These applications pull meter data to communicate comprehensible billing and energy use information to customers.
- **Web Portal:** A secure and accessible web portal will interact with customers providing them with the tools, support, and educational materials to understand their energy

consumption data and the insight to manage their energy usage effectively. This interface will empower customers to become active and informed energy consumers.

- **Green Button Connect My Data:** This system gives every utility customer the ability to securely authorize both National Grid and designated third parties to send and receive their energy usage data.
- **Customer Education and Engagement:** National Grid is prepared to pair the enabling technology of AMF with proactive customer engagement initiatives in order for the benefits of smart meter technology to be fully realized by the customer. National Grid's three-stage program prepares customers to engage with the new technology and data streams as well as integrate with other energy modernization efforts.
- **Integrated Network Operations:** The Integrated Network Operations Center ("INOC") oversees the day-to-day operations for the smart meter program. This function is a component of the broader INOC that is part of the grid modernization investment plan in the Company's initial DSIP. The INOC will oversee the AMF rollout and respond to any meter related issues that occur during that phase. Once the rollout is complete, the INOC will mature into the central management hub to mitigate any meter related issues.

1.4 Key Input Assumptions and Sensitivity Analysis

There are a number of key business case input assumptions, both cost and benefit, that have a measurable impact on the results of the benefit-cost analysis. These assumptions are described below including their treatment, if any, in the sensitivity analysis that was performed as part of the AMF Business Case analysis.

- **Status Quo AMR Replacement:** National Grid currently has a fleet of automatic meter reading ("AMR") meters covering its service territory that it expects to replace in the early 2020's according to operational life expectancy documentation from the vendor. The AMF Business Case considers only the AMF costs above and beyond the baseline AMR replacement.
- **New York/Massachusetts Back-Office IT/IS Cost Sharing**: Back office IT/IS costs can be shared across National Grid's operating companies. The AMF Business Case evaluates as a sensitivity the impact of shared costs between National Grid and National Grid's Massachusetts affiliates, Massachusetts Electric and Nantucket Electric. AMF implementation is under consideration for both of these affiliate companies as part of the Massachusetts Grid Modernization proceeding. Hearings in this proceeding are currently scheduled to conclude late this year.
- **AMF/Initial DSIP Cost Sharing:** Certain cost components, such as IT/IS and Cybersecurity enable both AMF and the other grid modernization and DSP elements of the initial DSIP and thus are appropriately shared with the DSIP filing. If the AMF is approved and elements of the DSIP are not, these shared elements would need to be fully supported by the AMF effort.

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- **Meter Deployment Opt-Out:** Meter deployment opt-out is an area with large potential variability due to the uncertainties associated with the public perception of smart meter technology. The experience of other U.S. utilities show opt-out rates as low as one percent while National Grid's Massachusetts affiliate observed opt-out rates approaching six percent during the Worchester Grid Modernization pilot. National Grid experienced an AMR opt-out rate of approximately one percent. Under Deployment Options A and B the AMF Business Case assumes a two percent opt-out rate.
- **Time-Varying Rates Pricing Program Opt-Out:** The deployment of AMI meters will be accompanied by new rate structures. These programs do not mandate customer participation, and can be deployed as Opt-In (with approximately 20% participation anticipated) or Opt-Out (with approximately 80-100% participation anticipated, depending on the scenario analyzed). Benefits are significantly more impactful in an Opt-Out approach which is to be considered further as part of the REV Track 2 proceeding. This assumption is evaluated as part of the AMF Business Case sensitivity analysis.

An essential feature of the AMF Business Case analysis was the thorough examination of a range of variables that influence the economics of each deployment option. To articulate the range of likely outcomes for each deployment option two sensitivity scenarios are presented in the benefit-cost analysis. The key deployment option sensitivity scenarios are summarized as follows:

Sensitivity Scenario 1

- National Grid and National Grid's Massachusetts affiliates share back-office IT/IS costs – Option A: 55%/45% (Upstate New York / Massachusetts), Option B: 42%/57%, and Option C: 15%/85%;
- Time-Varying Rates - Customer participation rates vary among scenarios under an Opt-Out pricing program model. – Option A: 80% participate, Option B: 90% participate, and Option C: 100% participate.

Sensitivity Scenario 2

- All back-office IT/IS costs, 100%, are attributed to the Upstate New York service territory for all deployment scenarios.
- Time-Varying Rates achieve 20% participation for all deployment scenarios under an Opt-In pricing program model.

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1.5 AMF Benefit-Cost Analysis

The results of the AMF Business Case analysis are found below in Figure 2. The analysis was performed in alignment with the Commission's recent Order Establishing the Benefit-Cost Analysis Framework ("BCA Order")[2] and the Company's BCA Handbook.

20-Year NPV ($ in Millions)		A: Full Deployment		B: Urban Deployment		C: Dispersed Deployment	
Number of Electric Meters		1.7M		0.7M		0.17M	
Number of Gas Meter ERTs		0.7M		0.3M		0.07M	
MA/NY Back-Office IT/IS Cost Sharing		NY 55%	NY 100%	NY 42%	NY 100%	NY 15%	NY 100%
Pricing Program Participation Rates		80%	20%	90%	20%	100%	20%
Scenario		1	2	1	2	1	2
Benefits	SCT Benefits	603.22	451.46	248.09	193.56	143.77	84.69
	UCT / RIM Benefits	467.54	339.77	195.39	145.33	131.45	73.81
Costs	Capital – Full AMF	382.77	392.21	185.55	197.75	73.37	91.53
	Capital – AMR Replacement	(110.15)	(110.15)	(43.89)	(43.89)	(15.67)	(15.67)
	AMF Net Capital Expenditures	272.62	282.06	141.66	153.86	57.80	75.86
	Operating Expenditures	147.85	168.94	106.08	133.33	150.35	190.67
	SCT Costs	420.47	451.00	247.74	287.20	208.16	266.53
	UCT / RIM Costs	420.47	451.00	247.74	287.20	208.16	266.53
SCT Ratio		**1.43**	**1.00**	**1.00**	0.67	0.69	0.32
UCT / RIM Ratio		**1.11**	0.75	0.79	0.51	0.63	0.28
Est. Monthly Customer Impact (per meter)[3]		$ 2.37	$ 2.49	$ 3.04	$ 3.41	$ 9.25	$ 11.58

Figure 2: Benefit-Cost Analysis

1.6 AMF Benefit and Cost Components

The following charts shown in Figures 3 and 4 highlight the major benefit and cost components for Option A – Full Deployment across a 20-year time horizon.

[2] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) ("BCA Order").

[3] The Estimated Monthly Customer Impact is a value calculated to provide an understanding of how the basic service fee of Upstate New York customers would reflect National Grid's AMF investment. The dollar per meter value derived for each Option and corresponding Scenario does not reflect a customer class allocation. The value is calculated by (1) present valuing an estimated revenue requirement stream calculated for the 20 year business case timeline, (2) translating the NPV revenue requirement into a levelized annual payment, and (3) distributing the levelized revenue requirement to the in-scope electric and gas meter count on a monthly basis. The initial revenue requirement stream is calculated in accordance with PSC Case No. 12-G-0202 / E-0201, Rate Year Ending March 31, 2016 methodologies.

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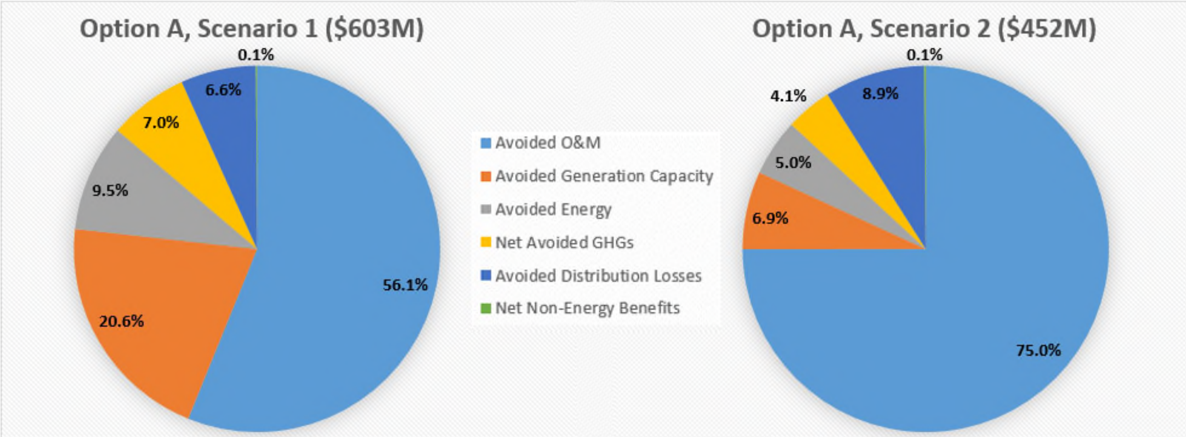

Figure 3: AMF Business Case Benefits Components for Option A

The AMF Business Case analyzed benefits within the BCA Order framework and identified the majority of AMF benefits to be a result of avoided operations and maintenance expenses where the amount of this benefit changes very little from Scenario 1 to Scenario 2. The Opt-Out vs. Opt-In assumption of Critical Peak Pricing ("CPP") accounts for the major differences in the benefits realization between Scenario 1 and Scenario 2, affecting avoided generation capacity, avoided energy, and avoided greenhouse gases.

The remote metering and communication capabilities of AMI meters and ERTs provide a variety of opportunities for Avoided O&M benefits, the largest benefit category realized by the AMF Business Case. Avoided O&M savings are the direct result of data-driven decision-making by both the utility and the customer. Three subcategories, reduction of meter inspections, remote metering capabilities, and improvement in bad debt write-offs, make up approximately 90% of Avoided O&M savings. These savings come when labor and vehicle resources are reduced because on- premise visits are no longer required to investigate, connect, or disconnect a meter after the proper customer contact process has been performed. In addition, data granularity and remote disconnect capabilities together improve debt collections and reduce the Company's net write-off expense.

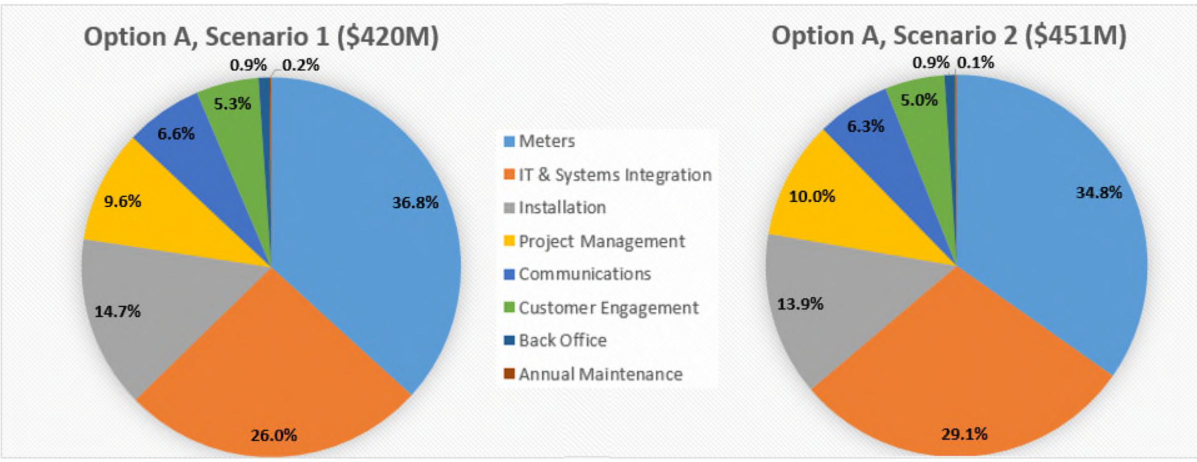

Figure 4: AMF Business Case Cost Components for Option A

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In both scenarios, meter and ERT equipment and installation together account for approximately half of the AMF cost. The software, labor, and hosting and analytics capabilities housed within the Information Technology and Systems Integration costs portion contribute over one-quarter of the total cost.

1.7 Proposed Direction

The BCA Order's Societal Cost Test ("SCT"), Utility Cost Test ("UCT") and Rate Impact Measure ("RIM") support the pursuit of Option A, Full AMF Deployment across National Grid's electric and gas service territory. The number and large expense for systems that allow meters and ERTs to be brought online falls marginally as the scope of deployment decreases from Option A to C. As such Option A, Full Deployment, spreads consistently large costs out over the largest group of customers, making it the most economical on a per meter basis. Beyond the economics, there are a number of intangible benefits associated with AMF, the most important being the ability to put National Grid on the path toward achieving REV goals and positioning National Grid to help usher in an energy future for the benefit of its customers and the State of New York.

1.8 AMF Deployment Timeline and Investment Plan

The proposed AMF implementation timeline is six years beginning in fiscal year 2019.

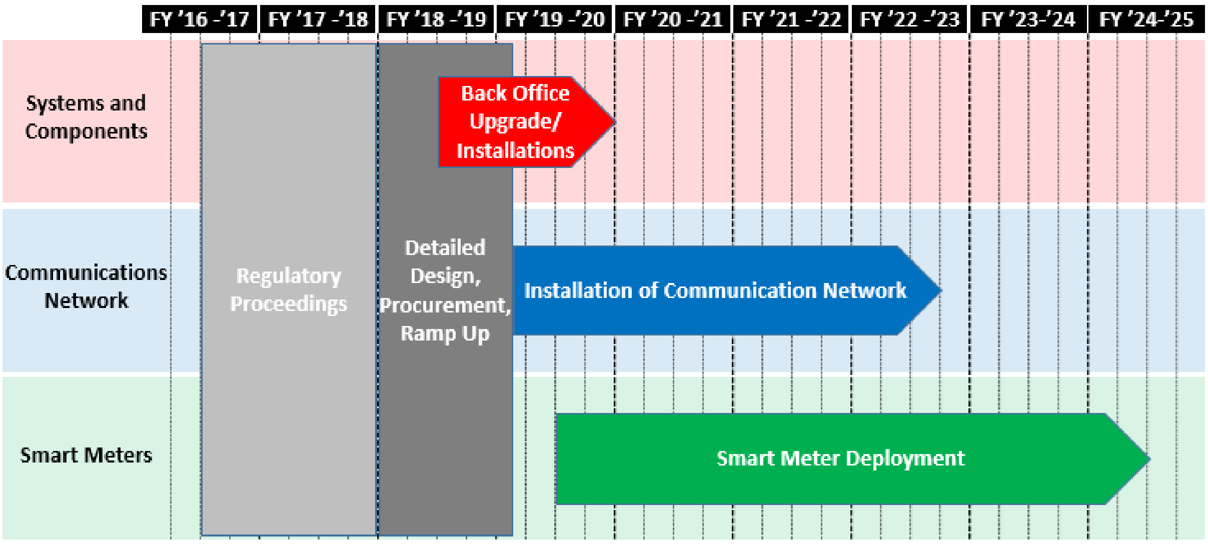

Figure 5: National Grid implementation schedule

The start date for the project reflects the time required to engage stakeholders following the initial DSIP filing to further develop and refine the plan, and to achieve regulatory approval either separately or as part of a general rate case. The anticipated timing of the filing of National Grid's next electric and gas general rate case is within the first half of 2017. Year 1 of AMF implementation includes detailed technology design and the formal procurement process, followed by the installation of back office systems and communication infrastructure. This will be followed by a five-year meter and ERT installation program.

Capital and O&M investments in the first five years are estimated at approximately $256M (in 2016 dollars) and an additional $316M (in 2016 dollars) is forecasted over the subsequent five year period. The annual spending is included Figure 6 below.

	Capex ($m)								Operation & Maintenance ($m)							
Project	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21	5-yr Total	Yr5-10	10-yr Total	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21	5-yr Total	Yr 5-10	10-yr Total
Advanced Metering Functionality			26.8	88.9	93.2	208.8	253.1	461.9	0.0	0.0	11.2	18.1	18.0	47.2	62.9	110.1

(Investments are estimated in 2006 dollars)

Figure 6: AMF high-level investment plan

2 INTRODUCTION

National Grid's AMF Business Case was developed in response to an evolving regulatory and market landscape in New York State. The AMF Business Case assesses alternative AMF deployment options and demonstrates the viability of a full electric and gas smart meter technology deployment to all National Grid customers, as well as supporting infrastructure and systems. This program builds the foundation to support fundamental change in the energy future of our customers, the electric distribution system and the State of New York. New technologies, especially in the areas of communications and coordinated controls, can enable significant changes in customers' experiences and empowerment, as well as in how the grid operates. These technologies, which have only become cost effective and more widely used recently, are central to the opportunities envisioned in the Public Service Commission's ("PSC") REV goals.

National Grid's AMF Business Case evaluates the benefits and costs of the advanced metering functionalities and underlying enabling technologies to move operation of the distribution grid towards greater levels of efficiency and reliability. The AMF Business Case also enables new sources of innovation and a cleaner and more environmentally-friendly industry. Under an AMF-enabled future, customers will have more information and greater control over their energy usage and associated costs, access to an energy marketplace, and the ability to choose new and innovative energy solutions from vendors. Further, AMF enables the use of metering data to support other DSP planning functions such as demand modeling, load forecasting, and capital investment planning.

2.1 New York REV Overview and DSIP Requirements

REV and other REV-related proceedings are focused on transforming New York's retail electricity market and its energy efficiency and renewable energy programs. The vision of REV is a cleaner, more affordable, more modern, and more efficient energy system across the state of New York. For utilities, these gains are manifest through six objectives:

- Empowering New Yorker's to make more informed energy choices and providing them the tools and insight to manage energy usage effectively;
- Animating a consumer energy market environment for third-party energy solution providers to attract and deploy capital and create new business opportunities;
- System-wide efficiency gains by operating more effectively across all aspects of the grid including generation, transmission, and distribution;
- Greater fuel and energy diversity by supporting a broad range of renewable and EE initiatives and reducing soft costs and other market barriers;
- System reliability and resiliency improvements through the integration of DERs into the grid during both 'blue sky' days and significant system events; and
- Cutting Greenhouse Gas Emission 80% by 2050.

By investing in AMF, National Grid will be taking a key step toward achieving these REV objectives as well as enabling the Company to assume the role of the DSP. In this role, utilities

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will construct, operate, and maintain highly integrated technology platforms, allowing the incorporation of third-party owned DERs, which can include DR, EE, storage, and on-site generation. These technologies will be tightly integrated into the utilities' distribution infrastructure. Ultimately, enhanced monitoring and control of these resources may support the establishment of a marketplace where commodities from these resources can be exchanged between Energy Service Companies ("ESCOs"), aggregators, customers, and other interested parties.

The Distributed System Implementation Plan Guidance ("DSIP Guidance") found that "advanced metering functionality will be an important contribution to enabling utilities to assume the role of the DSP" (page 58 of DSIP order). The DSIP guidance called for utilities to include a summary of the most up-to-date AMI rollout plans over the next five years in their Initial DSIP filings. The DSIP Guidance also requires AMI proposals to be accompanied by a detailed business plan and specified minimum business plan requirements which are addressed herein.

The initial DSIP requirements are organized into three categories: Distribution System Planning, Distribution Grid Operations, and Market Operations. Each of the three categories have a number of requirements associated with it, which may be seen in Figure 7. The goals of AMF deployment most closely align with the objectives described in the Market Operations category. This is understandable given that the technology and systems associated with standing up smart meters build the foundation for market operations.

Distribution System Planning	Distribution Grid Operations	Market Operations
• Forecasting demand and energy growth; • DER investment planning and programs; • Capital Investment Planning; • DER deployment planning; • Grid infrastructure investment planning; and • Probabilistic Modeling and Load Flow Analyses.	• Systems operations; • Situational Awareness; • Volt/VAR optimization; and • Streamlining the interconnection process.	• Greater data granularity; • Data accessibility for consumer and market participants; • Greater transparency to market participants of system and operations needs; and • Ensuring privacy and security.

Figure 7: DSIP categories and objectives

The Initial DSIP is a comprehensive plan that considers numerous components working together in an integrated fashion. In performing this assessment, the full scope of the DSIP was considered with the central assumption that AMF will be deployed as part of this larger whole. Thus, if direction is given that AMF needs to exist independently, additional analysis will be required to determine the full standalone costs, as certain Initial DSIP costs are currently structured in a way where they are shared by the multiple enabling capabilities across the programs.

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With this key assumption in mind, there are three AMF deployment options evaluated and presented as a part of the AMF Business Case. The three options may be seen in Figure 8 and are discussed in greater detail in the following sections of this report.

Option	Description
A	Full deployment of both electric AMI meters and gas ERTs across National Grid's service territory.
B	Deployment of both electric AMI meters and gas ERTs across National Grid's service territory in high-density population areas (approximately 40% of total electric and gas meter points).
C	Deployment to any customers in National Grid's service territory who choose to opt-in (approximately 10% of total electric and gas meter points)

Figure 8: High-level descriptions of National Grid's deployment options

2.2 Current State Characteristics

2.2.1 Customer Characteristics

National Grid's Upstate New York service territory spans more than 25,000 square miles and actively supports approximately 1.7 million electric and more than 680,000 gas metering points. Dual fuel customers total around 500,000. The service territory is not contiguous, and it spans from the eastern to western to northern borders of the state. Customer density also varies significantly throughout the service area from dense urban to very rural.

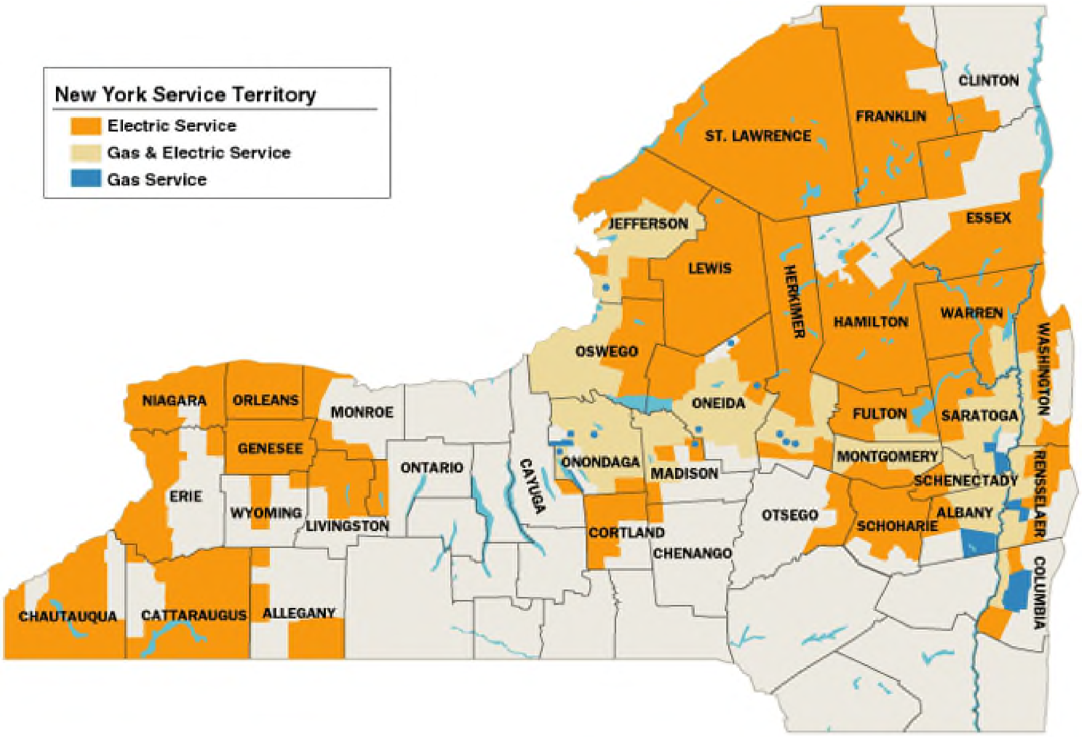

Figure 9: National Grid's Upstate New York service territory

In addition, National Grid tracks approximately 170,000 electric and 90,000 gas meters which are inactive at any given point. Approximately one-third of these meters have been inactive for less than one year and are therefore considered temporarily inactive. Analysis for AMF deployment has considered all active and temporarily inactive meters.

2.2.2 Existing Metering, Communications and IT Systems in Service Area

The majority of electric and gas meters throughout the Upstate New York territory use AMR technology. The meters were originally deployed in a major program during the period 2002 through 2004. Approximately 99% of customers in the territory have electric and gas meters, where monthly reads are acquired through radio frequency collection. These collections are done by a fleet of company service vans which drive along routes to allow communication with each meter. The majority of these meters are scheduled for replacement in the early 2020's based on their operational life expectancy.

In addition, a small number of larger wholesale C&I customers and retail customers have interval meters, which currently communicate through public cellular connections or through wireless TCP/IP communication modules.

2.3 Advanced Metering Infrastructure and Supporting Technology Overview

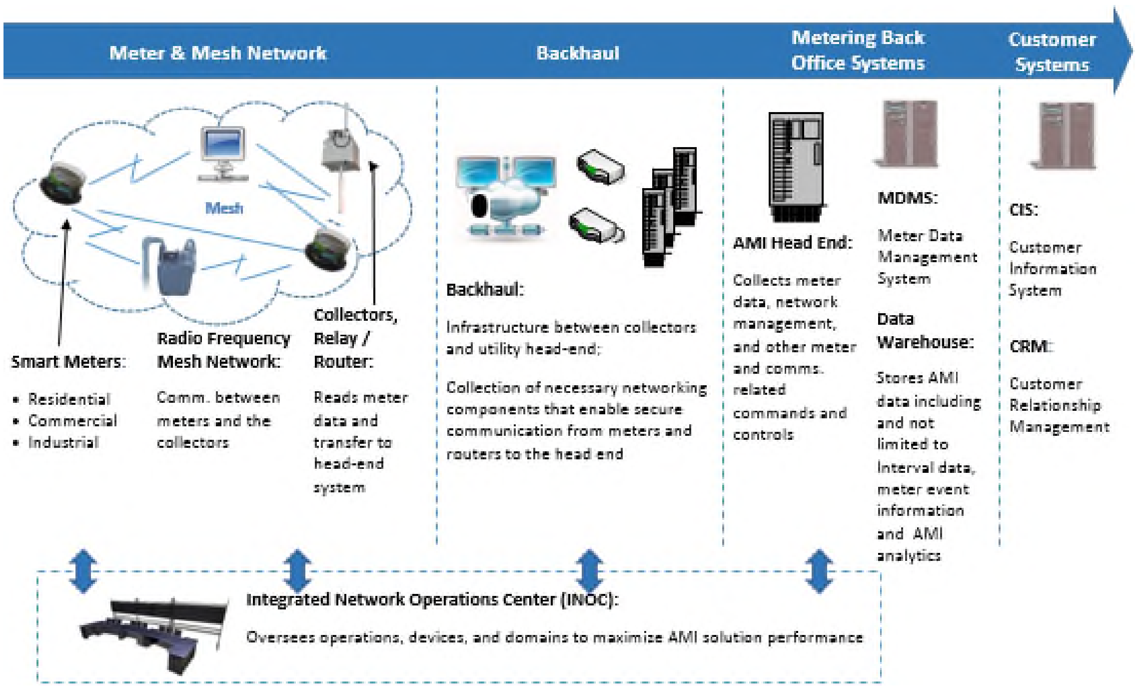

Figure 10: Illustration of smart meters and supporting technology

The AMF program is based on the concept of transitioning from the current fleet of AMR meters to an AMI for all options. The components of this upgraded metering architecture are illustrated in Figure 10. As shown, it is comprised of AMI meters for electric customers and ERTs

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for gas customers, a wireless communications infrastructure, and various back-office systems which securely capture and store electricity and gas consumption data.

These technologies allow for greater granularity in measuring customer energy consumption for billing, remote meter reading, remote disconnect/reconnect, and enhanced diagnostic capabilities to assess outage for all customers who receive a smart meter. These meters and their associated infrastructure are assumed to be deployed across the upstate New York territory over a six-year timeframe.

2.4 AMF Objectives

As a key element of the PSC's REV vision, AMF will be the enabling framework to engage customers and third party providers. The objectives include:

- Empowering greater customer control over energy usage through participation in DR, EE programs, and pricing programs;
- Allowing granular electric and gas consumption data to be available to customers and approved third party vendors in a timely and efficient basis;
- Providing customers access to a marketplace, and the ability to choose new and innovative energy solutions from vendors; and
- Increasing grid reliability and resiliency.

2.5 Review of Business Case Methodology

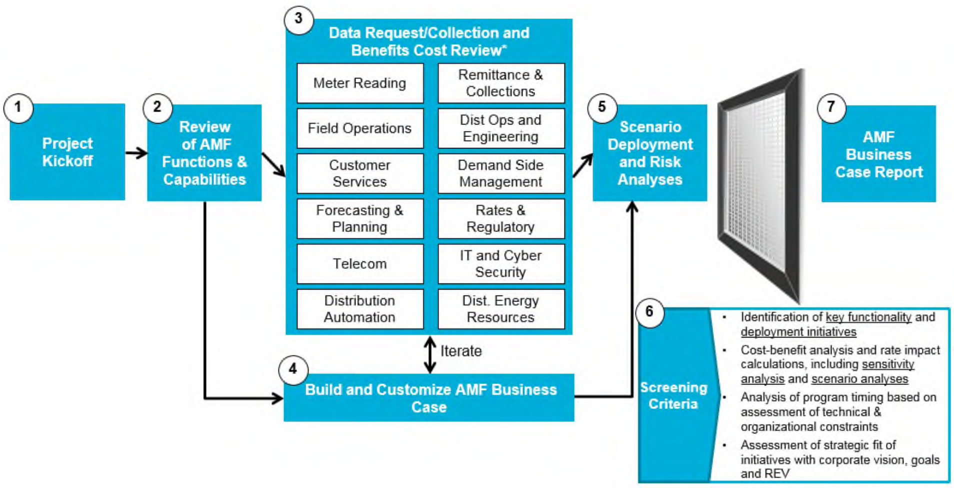

Figure 11: Depiction of the AMF Business Case methodology

The methodology to produce the AMF Business Case, as illustrated in Figure 11, was implemented over the course of 10 weeks and consisted of six steps.

1. The initial phase was the project kickoff where the team aligned expectation and scope, walked through the approach, set the project work plan, timeline, and deliverable due dates;

2. From there the team performed an in-depth review of the AMF functionalities and capabilities National Grid would like to include in the AMF Business Case model. The team detailed the technologies and systems considered in-scope, targeted customer populations and rate classes, implementation timeline, deployment length, and potential cross-jurisdictional benefits;
3. The team also defined the benefit and cost calculations expected as part of the filing and aligned them to the PSC's Benefit-Cost Analysis ("BCA") framework. The agreed upon calculations included in the model, along with several workshops, helped the team define the "as-is" system and infrastructure conditions. These workshops also helped align the core team and the wider group of stakeholders of expectations and data needs;
4. Once a sufficient amount of data was received the team started to build and customize the AMF Business Case model and conduct reviews with the core team and wider company stakeholders;
5. These reviews were pivotal in refining the scenarios, and defining and analyzing the associated risks;
6. Upon receiving general consensus that the inputs were in-line with expectations and the benefits and costs for each scenario aligned to publically available information on AMI deployment and other National Grid programs, sensitivities, and risk analysis were performed, which are all detailed later in this AMF Business Case.

The data flow of this model, which may be seen in Figure 12, processes various data inputs provided by National Grid (and augmented with estimates where necessary) to build high-level costs and associated benefits of AMF installation. These inputs, combined with deployment schedules, enable the team to build annualized costs and benefits for the electric smart meter deployment. This base case combined with the incremental costs and benefits of a simultaneous gas ERT deployment and the depreciation schedules drive the revenue requirements.

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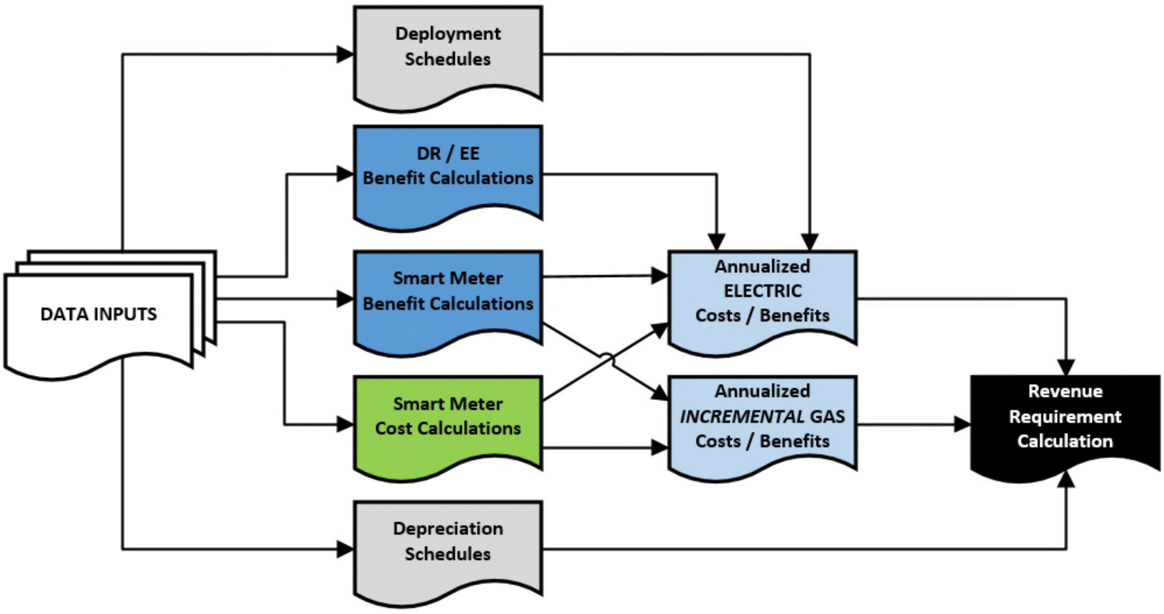

Figure 12: Depiction of the AMF Business Case tool

2.6 Cross-Jurisdictional Impacts

As part of the AMF Business Case scope, a high-level assessment of the AMF systems and functions was performed to ascertain the potential to leverage these components across operating companies. While many components by their nature are exclusively dedicated to the Upstate New York territory, there are others that have the potential to be scaled such that they can be utilized across jurisdictions. A number of assumptions were made in this area that will be reviewed and refined as the AMF Business Case is advanced into a filing for regulatory approval.

National Grid's Massachusetts affiliates spent approximately 18-months developing a comprehensive plan for distribution grid modernization, which is materially similar to the platform envisioned for Upstate New York. This plan was filed with Massachusetts regulators in September 2015 and is still being evaluated. Many of the concepts, learnings, and directional cost estimates have been shared internally as part of this AMF Business Case to establish many parameters for the baseline AMF Business Case.

In reviewing the Massachusetts plan and developing the New York plan, there are numerous functional requirements in common for both jurisdictions that can fairly easily be scaled to minimize redundant costs and effort and maximize efficiencies across both territories. There are unique considerations in each of the territories to be accommodated, but the core overlapping assets and associated efforts will be similar, and include:

- Customer Service System ("CSS") modifications – to handle more granular meter reading information for bill processing;

- Meter Data Management System ("MDMS") – to handle more granular meter data which in turn enables customer analytics;
- Advanced Metering Infrastructure Head End ("AHE") – to manage data collection and distribution between meters in the field and back-office systems;
- Systems Integration ("SI") – various information technology services required to manage data interfaces between different systems; and
- Process Design – definition of new processes to be followed by field and office workers to maximize the effectiveness of the new system.

Ideally, the Massachusetts Grid Modernization program will be approved, and these efficiencies can be fully realized. However, various assumptions and risks should be acknowledged which may have a significant bearing on the economics of the AMF Business Case as articulated throughout. These include:

- Cost Sharing & Give Backs: Regulators in Massachusetts would likely require costs initially born by Massachusetts ratepayers to be reimbursed or shared by New York ratepayers; the team assumed that total back-office IT/IS costs will be pro-rated based on metering points count per jurisdiction and allocated between Massachusetts and New York accordingly.
- Massachusetts Grid Modernization Rejection: If Massachusetts regulators reject or require significant modifications to the Grid Modernization plan, but New York approves the Upstate New York AMF portion of the DSIP, all systems and integrations enabling the New York platform will need to be supported by New York customers, which in turn impacts the economics of the AMF Business Case.
- Enterprise Standardization: Many efficiencies can be realized where programs, capabilities, and data flows are identical between jurisdictions. Where operational considerations vary for unique market conditions or regulatory constraints; customizations will erode these efficiencies and impact the economics of the AMF Business Case.

3 END TO END ADVANCED METERING FUNCTIONALITY TECHNOLOGIES

The following descriptions of the end to end metering technologies are meant to provide a broad explanation of the capabilities of individual components that will be largely unchanged across the three options presented in this document. Based on numerous past engagements, the team has found these components and technologies necessary to implement and operate an effective and efficient AMF platform.

As the AMF Business Case is conceptual at this point, descriptions of components and capabilities defined herein do not constitute a complete list, nor are they linked to any particular vendor or vendors. Rather, it is intended to be directional in nature, establishing the order of magnitude of a comprehensive scope of deployment.

A full articulation of the scope and details on the capabilities will be defined following stakeholder input and considerations raised by PSC.

3.1 <u>End Point Devices</u>

3.1.1 Smart Meters

A smart meter is an electronic device used to measure electricity and/or gas consumption at residential, commercial, and industrial locations. This device then digitally communicates the interval data using two-way telecommunications infrastructure. These devices can be equipped to leverage either a cellular radio or a mesh network, to interface with a utility's backhaul and back-office systems.

In all cases, it is expected that electric meters will have a full kit upgrade including meter, module, and communications device. With gas meters only the ERT module (a communication device that is capable of securely and efficiently sending information packets a short distance) is expected to be switched out. Gas regulators and meters were not included as part of the scope of this program and will continue to be replaced per current O&M schedules (understood to be approximately 20,000 meters per year).

A smart meter has a number of capabilities depending on the type of meter and whether it measures electricity or gas:

3.1.1.1 Capabilities of both gas and electric meters:

- Tamper detection;
- Better, more reliable measurement;
- Real-time data query: As initiated by customers through the web portal, customer service agents, or control center operators, the meter can be pinged to report current readings which can then be used to determine power consumption, outage status, voltage status, and other characteristics;
- Interval granularity: Meters are typically configured to capture energy consumption at 15-minute intervals. As the concept of near real-time data takes hold, more frequent consumption checks, on the order of five minutes, may occur; and
- Reading frequency: Energy consumption data is typically transmitted back to the AMI Head-End three to four times a day. This data transmission may eventually be streamed in near real-time allowing customers to view their energy usage from moment to moment.

3.1.1.2 Capabilities of electric meters only:

- Ability to provide voltage monitoring and real-time notifications for voltage violations;
- Power outage notifications ("PON") where the meter automatically notifies the back-office systems of a loss of power;

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- Power restoration notifications ("PRN") where meters proactively communicate that power has been restored;
- Remote connect, disconnect, and reconnect as allowed by state regulations;
- ZigBee communications to interact with Home Area Network ("HAN") devices as last mile of DSP-initiated DR capabilities;
- ZigBee communications enabled real-time monitoring: ZigBee can independently interact with other customer procured monitoring equipment for real-time monitoring;
- Dead-band settings to locally communicate load changes whenever consumption patterns alter by more than 10 watts;
- Remote firmware upgrades: Allows for enhanced capabilities to be deployed over time, as well as timely updates to address security threats as identified, without the need for manual intervention; and
- Remote diagnostic: National Grid's INOC will have a dedicated smart meter monitoring function that can ping individual meters to test communication pathways and responsiveness.

3.1.1.3 Capabilities of gas modules only:

- Remote disconnects (assuming meters are also replaced);
- 20-year battery while supporting standard data collection patterns (e.g., 15-minute intervals, collected three times daily, with approximately three firmware upgrades throughout its deployment lifespan); and
- Five-year expected battery life for any meters where customers have opted for advanced data collection patterns (e.g., 15-minute intervals, collected hourly, with approximately 3 firmware upgrades throughout its deployment lifespan).

3.1.2 DER, ADA, and HAN Devices

As National Grid's AMF capability stabilizes and medium-term DSIP initiatives are considered, additional grid modernization technologies could potentially leverage the mesh network anticipated to be constructed as a part of AMF. These additional technologies include:

- Advanced distribution automation ("ADA") devices typically include fault current indicators ("FCI"), capacitor banks, and voltage regulators;
- DERs vary from residential to utility scale and can include technologies such as energy storage, electric vehicles, solar generation, and fuel cells.
- ZigBee-based HAN devices like thermostats, water heaters, and pool pumps that may be enabled to communicate with the utility for DR initiatives.

These devices have the potential to increase the capability of the network by adding to the density of the mesh network, while performing their dedicated tasks on the grid.

3.2 Field Area Network

Embedded within each meter is a communications module that enables the meter to communicate with back office systems. These modules can either be outfitted with mesh or cellular radios, each of which is best suited to a different set of project economics. Circumstances like relatively populated densities, topography, seasonal conditions, and other strategic factors may influence the type of communication utilized. By understanding the economic and strategic considerations and combining these modules appropriately, an optimal deployment can be achieved.

3.2.1 Radio Frequency Mesh Network

The radio frequency mesh network is created by including a low-power, short-range radio in each meter. Each meter is able to transmit its own load profile as well as a finite collection of data from downstream meters. All meters with this technology dynamically communicate with each other to identify optimal communication pathways back to centralized data collection points. In doing so, these networks of devices can self-identify the most efficient paths on an ongoing basis and dynamically reconfigure to maintain optimal routing in varying operational situations.

For most urban/suburban areas where a sufficient population density exists, National Grid will utilize this radio frequency mesh network to facilitate meter communication with the backhaul system. The meters will utilize a relay/router system to transmit the meter data back to the back-office systems, as well as transmit data from the back office to the meters in the field in a bi-direction manner.

When possible, the electric meter will serve as the communications platform for the gas meter. The platform will enable communication between the gas meters and the back-office systems while efficiently optimizing impacts to the gas meter's battery life.

3.2.2 Cellular Radios

In certain circumstances, a cellular radio will be used instead of the mesh network. The conditions for cellular radio use include economic or strategic reasons, lack of population density to support a mesh network, and C&I customers with a sufficient magnitude of energy usage to warrant closer observation.

For deployment Options A and B, it is assumed that approximately five percent of devices will be direct cellular. Under Option C, the opt-in scenario, our assumption is 100% of meters will be outfitted with cellular radios.

3.2.3 Collectors/Relays/Routers

Collectors, relays, and routers are the equipment that facilitates transmission of data from the mesh network linked smart meters to the back-office systems. It should be noted that there are innumerable infrastructure configurations possible for the communications network. The transmission of data may utilize multiple types of devices from a variety of vendors, which pull in and transmit data to the next node in the communications pathway on the way to the back-office system.

The collectors, relays, and routers have a number of characteristics that enable communications efficiency and effectiveness. They are:

- The network is able to rearrange itself dynamically to maintain the most efficient communications pathways across seasons, varying weather conditions and vegetation cycles;
- In the event of a power outage, the FAN will stay up long enough to transmit a power-off notification to alert the outage management system ("OMS") of the problem;
- Multiple types of devices that collect and transmit digital interval data:
    - Collectors: larger bandwidth devices for maximum throughput of data to manage data collections;
    - Relays: smaller device that is used to extend the range of communications for Spur; and
    - Meters: small short range device used to aggregate a small number of meters.

It should be noted that, depending on overall network design and configurations implemented in each device, data transmission can slow. While typically not problematic for standard meter data used exclusively for billing purposes, more advanced use cases could demonstrate sub-optimal performance if design thresholds are violated. As such, this means of communication should be a fit for purpose design. Discussions for this AMF implementation have explicitly anticipated that DER, reclosers, and certain DR capabilities would not be communicating through the AMF wireless communications network.

3.2.3.1 Real-Time Smart Meter Data Collection

As part of the AMF Business Case, various emerging capabilities were reviewed in the smart meter landscape. One feature on the horizon is the near real-time data collection from smart meters that allows bill quality data to be accessible for customer download within several hours of billing interval completion.

It should be noted that real-time data collection is conceptual at the time this report was finalized. While metering vendors in this space have given estimates of the achievability of "real-time" data collection, limited deployments with this level of data capture have been identified for benchmarking purposes.

However, for this capability to be implemented, it is reasonable to estimate that additional infrastructure is required to meet an enhanced service level. As such, approximately 10% more additional collectors, relays, and routers would be required in each scenario to support more frequent communication and to compensate for bottlenecks.

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3.3 Backhaul

The backhaul network, which is typically a wide area network ("WAN"), is the high-speed, high-bandwidth communications structure between the collectors and the AMI Head-End. The network can either be public or private depending on several factors, including cost (both upfront and reoccurring), security, meter density in the area and distance from the existing fiber network.

A private system would have collectors daisy chained to centralized fiber optic or microwave communications infrastructure. A public system would utilize the network of a third party vendor, typically a wireless cellular carrier, to transmit the data from collectors to the AMI Head-End. Given National Grid's extensive Upstate New York territory, its varied topography, and the expected financial impact of extending a private network across the region, for Options A and B of the AMF Business Case the backhaul will leverage a public cellular telecommunications network to transmit the aggregated data from the collectors and routers to the back-office systems. In consideration of Option C, the meters will directly connect to the public backhaul for data transmission.

3.4 Systems and Integration – Core AMF/AMI

3.4.1 AMI Head-End

The AMI Head-End is the communication, command, and control system that integrates the communications infrastructure in the field and the back office systems. The AMI Head-End communicates with the smart meters to collect meter data from reads and events. It also can ping individual meters as necessary and push firmware updates across the network. For electrical systems, it can remotely initiate the connection and disconnection of meters. This system serves as the main point of data collection and disbursement for data being transmitted in either direction, to/from meters.

3.4.2 Meter Data Management System

An effective AMF platform requires an MDMS. The MDMS provides smart meter data storage and archival capabilities for interval meter read information. The MDMS also processes the incoming meter data by VEE the interval data that is received by the program. Once the raw data has been processed, it can be utilized by back-office systems like billing, customer service, and data analytics. In addition, the data can be uploaded to the web portal for customer use and/or authorized market participants.

An important function of the MDMS is the VEE process. This is a method where the MDMS reviews all un-validated data from the smart meters in an effort to identify anomalies. This is data that fails validation because it falls outside an expected range and is flagged for review by metering agents. In addition to failed validations, incomplete or missing interval reads are also highlighted. These flagged data intervals are estimated as the final step of the process and can be updated once additional data has been received or the original data has been validated.

3.4.2.1 Real-Time Smart Meter Data Collection

While the baseline capability proposed is to provide bill quality data within 24 hours of collection (after VEE processing), several possible scenarios have been evaluated as part of the AMF Business Case to expedite this process. Due to the increased processing requirement of the system, approximately 50% more server hardware will be necessary to process this information within several hours of the end of a specified interval.

At the time this report was finalized, real-time data collection was still conceptual, and therefore no specifications for system architecture could be defined. Vendors in this space have given estimates of the achievability of "real-time" data collection and processing. Limited deployments, with this level of data capture, have been performed. At this time, only estimates of additional processing infrastructure are available, and therefore have a lower degree of certainty.

3.4.3 Data Warehouse

The data warehouse is the back-office system that is the main archival database for the other systems. It is integrated across the back-office and provides archive support and retrieval functions. Due to the increase in the volume of information associated with AMF data granularity, the capacity to support data warehouse functionality will need to be augmented accordingly. A fully integrated data warehouse provides the following benefits:

- Central archive and data repository;
- Links multiple systems and facilitates data communication;
- Speeds up retrieval as it combines traditionally separate data archives; and
- Enables analytic capabilities for insights.

3.5 Systems and Integration – Secondary AMF Functions

3.5.1 Platform to Enable Future Capabilities

While the back-office systems of the previous section enable the core meter reading-to-bill function, National Grid's AMF vision transcends these historic boundaries to establish a foundation for emerging capabilities. The future state DSP will function in a way where meters perform double-duty by acting as a coordinated group of sensors throughout the territory. Combined with other capabilities envisioned in the DSIP, but outside the scope of the AMF Business Case, this enhanced metering data can be leveraged more holistically by various business units. These are units that have historically operated more independently; this is particularly true with real-time operations.

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The primary mission of real-time operations has been to restore outages as efficiently as possible and coordinate planned outages for maintenance and construction. However, in the context of modern-day customer expectations, technological advancement, and REV objectives, a new mission of "grid optimization" is emerging as a parallel to these historical themes. In this sense, AMF data is an enabler resulting in more accurate, more efficient outcomes for currently available capabilities such as outage location, voltage optimization, and DER integration, which are articulated further below.

In a broader historical context, it is important to note that the trend toward AMI, and these currently identified AMF capabilities, are still relatively new. New market participants, vendors, consultants, and ESCOs have been focused on electrical distribution like never before, resulting from the innovations currently being seen throughout the industry and being considered for implementation at National Grid. All indicators point to this trend continuing, if not escalating. While some of these capabilities are not yet known or possible to yet define, it is certainly reasonable to expect that use cases will emerge and utilize the information available from AMF.

3.5.2 Advanced Distribution Management System

Advanced Distribution Management System ("ADMS") is the emerging standard software suite used by distribution grid operators. It combines the traditional function of an OMS with newer functions captured by a distribution management system ("DMS"). While the functions of an ADMS are numerous, only a subset are covered in this report as applicable to AMF.

One of ADMS's core capabilities is to consolidate pertinent data from, and exert real-time control over, a variety of ADA devices like reclosers, capacitor banks, load-tap changers, voltage regulators, and fault current indicators. These devices can be coordinated by the ADMS to provide greater capabilities than what would be achievable if each device were to operate independently. Two notable functions are fault location, isolation, and service restoration ("FLISR") and Volt/VAR Optimization ("VVO"). AMF enhances each of these functions by providing additional data points for computation and algorithmic adjustment. ADMS will monitor distribution operations grid-wide and can provide indirect benefits to every customer even if they are located on circuits where no ADA and VVO devices were deployed and/or opted out of direct participation in the smart meter program.

ADMS significantly expands situational awareness for grid operators through a real-time view of system conditions. However, its critical function is to act as a coordination hub for the other systems and components, enhancing their effectiveness beyond the contribution of the individual components. An example of the synergies created by the systems communicating through a central hub is an outage event. During an outage event, AMI notifications can map the extent of the meters reporting a power outage. This data can then be used to coordinate ADA activities in the area of the outage to minimize its extent, and for circuits that can be reconnected, circuit voltages can be synchronized to restore power. These activities can all occur from the operations center.

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Further, data collected from meters can be used to develop more accurate load profiles for individual circuits. These are used within the ADMS as the basis for various algorithms.

3.5.2.1 Volt/VAR Optimization

VVO represents a family of optimization algorithms that can be deployed during various situations to improve operational characteristics. By monitoring and controlling capacitor banks, voltage regulators, and load tap changers, VVO algorithms can in some cases reduce energy consumption for all customers on a circuit by two to three percent without negatively impacting the customer experience. The operation of this function can be highly automated or initiated by direct operator intervention.

The ability to monitor grid conditions and automatically regulate power flow is especially important today. DERs, especially rooftop solar, have become more economical and efficient in recent years. In certain areas they have experienced substantial grid penetration, and this trend is expected to continue if not increase. While DERs have many benefits, the distribution network was not initially designed with non-point power sources in mind. Even though there is a certain robustness to the systems, over time, especially with greater DER penetration, volatility of power flow will increase (i.e. solar photovoltaics supplying power only during the day) and will make optimization all the more important. VVO has several benefits:

- Higher level of operator visibility into system operating parameters;
- Greater control over reliable and consistent energy delivery; and
- Greater control over optimizing EE, thereby saving customers money and emitting fewer greenhouse gasses.

Smart meters can enhance VVO further by designating a specific subset of meters as “Bellwether” meters. A bellwether meter is one that is configured to provide additional voltage data with greater frequency. They are particularly useful when placed at the end of a circuit where they perform the function of an end of line voltage monitor. This additional information can be leveraged in VVO calculations and to refine VVO adjustment algorithms further.

3.5.2.2 Fault Location, Isolation and Service Restoration

FLISR is a system comprised of substation equipment, circuit reclosers, and wireless communications infrastructure, along with software, meant to decrease the duration and the number of customers affected by isolation during outages. FLISR can compile data from various devices along the distribution network and compute the estimated location of a fault on a given circuit with ever-increasing accuracy. In response to this determination, it can coordinate the operation of specific field devices to connect un-impacted sections of distribution circuits to adjacent circuits. This has the effect of isolating an outage to as few customers as the infrastructure allows, or as the real-time operating conditions permit. FLISR can propose a series of actions for control center operators to adjust and authorize, or in high volume storm situations, can be configured to operate autonomously by isolating portions of the grid without the need for manual intervention to initiate preliminary restorations. Field crews must ultimately be dispatched to repair any damaged sections of distribution circuit, but fewer customers are inconvenienced in the interim.

Metering data from AMF are particularly useful in this scenario as it can be utilized to validate the restoration of power to impacted customers. In certain circumstances, meter data is also helpful in identifying nested outages within distribution segments that have been restored but might have been overlooked while restoring the primary outage.

3.5.3 Distributed Energy Resource Management Systems

Distributed Energy Resource Management Systems ("DERMs") are a suite of applications that integrate and manage DERs across the grid. DERMs rely on open protocols to leverage as much of the existing infrastructure as possible and integrates its applications with in-place systems such as AMI, and ADMS, along with DR devices and smart inverters to provide additional control and different types of control within the distribution network. As previously discussed, DERs can significantly affect the grid from a reliability standpoint and DERMs, through a suite of tools and dynamic pricing signals increase balance among inputs to maximize efficiency and reliability.

3.6 Customer Systems

3.6.1 Web portal

As part of the AMF deployment, National Grid will be building a web portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including smart meter interval data. This platform will allow customers to view raw data representing their consumption within four hours of the end of a given billing interval and to view billing quality data within 24 hours. Access to this data will enable customers to make better-informed decisions about how they use energy. The portal will power customer choice, giving customers the option to enroll in programs that can leverage the more granular data provided by AMF. These include EE, DR, and other pricing programs. Customers' can also access educational and safety information, material on energy efficient consumer products, and analysis on home energy usage. The platform will also be integrated with smartphone applications that allow customers to access their data on the go, in addition to being able to create customizable alerts notifying them of grid conditions (including outages, reductions or curtailments), unusual usage, and bill pay.

3.6.1.1 Green Button Connect My Data

Many utilities, including National Grid, have implemented Green Button Download My Data. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third party application.

Green Button Connect My Data takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf as may be seen in Figure 13. Upon authorization, energy usage data can be transferred as required. National Grid will implement Green Button Connect My Data as part of the AMF deployment program.

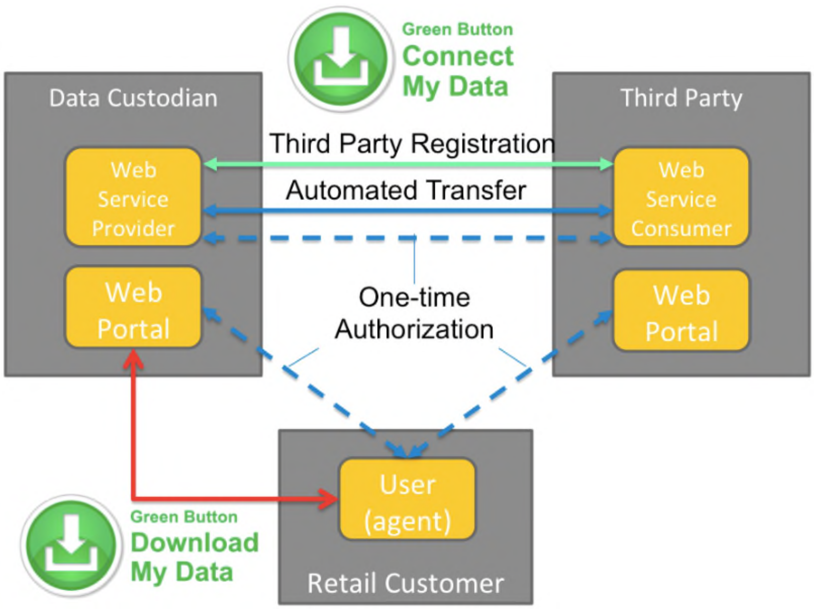

Figure 13: Standard communications protocol for Green Button Connect My Data[4]

3.6.2 Customer Service System

The CSS is a set of applications utilized to manage customer-facing activities. The set of programs pulls meter data to administer orders, billing and payment processing, collections, rebates and discounts for EE and DR, and other pricing program rates and usage. As part of the AMF deployment CSS will be modified and configured to accept data formatted for more frequent intervals. The CSS will also be configured with parameters to interpret this interval data so that usage can be priced by programs such as Time-of-use ("TOU") and CPP. Having such a prominent role in customer interaction with National Grid, an effective CSS with appropriate capabilities is critical to maintaining customer satisfaction. Moreover, as DER penetration increases throughout Upstate New York, CSS must be adaptable to changing with the dynamic energy environment.

[4] "Developers" Green Button Alliance, copyright 2015, 2016. Viewed June 2, 2016. http://www.greenbuttondata.org/developers/

The customer service system also includes capabilities intended to foster a relationship with customers and assist in customer retention through personalized service. The system pulls from various back-office IT/IS sources to create personal profiles on customers to facilitate customer engagement. For instance, CSS can be linked with interactive voice response ("IVR") to send an automated notification to customers when the system receives a power-off notification from smart meters. Additionally, the CSS will present customer history and real-time meter status to the call center operators when customers call in, giving National Grid employee's greater insights to help customers. Service representatives will also have a new suite of tools at their fingertips to perform diagnostic services instantly on or ping meters when issues arise. They will also have the ability to restore power that has been disconnected whether it be for non-payment or seasonal usage.

3.7 Integrated Network Operations Center

The INOC is the central management hub overseeing the day-to-day operations of the smart meter network, along with its associated communications infrastructure. During the construction and deployment phase of the AMF rollout, the center will manage communications infrastructure, meter deployments, and coordinate the initial stabilizations. The INOC will also be responsible for troubleshooting any meter related issues that crop up during that phase. Once the rollout is complete, the INOC will evolve into the central management hub. Its responsibilities include:

- Proactively managing and monitoring the smart meter and field area network performance;
- Remotely investigate/remediate meter and communications infrastructure problems;
- Dispatch technicians/vendors to remediate problems that cannot be done remotely;
- Manages firmware deployments;
- Manage meter swap-outs, repairs, maintenance and warranty issues;
- Manage the Meter Inventory Tracking System; and
- Manage the smart meter shop for the upstate New York service territory.

With large and complex grid modernization efforts, active monitoring of data flows between systems and overall security is essential. Given the comprehensive nature of the DSIP, this capability transcends the subset of functionality envisioned by AMF and is therefore captured outside of the AMF scope. However, given the importance of AMF's data, the INOC is also responsible for AMF managing the roll-out and communications stabilization. In this particular case, a Smart Meter Operation Center ("SMOC") mission is to be incorporated into the INOC, which has oversight of all IS-related items that support the grid. As such the INOC will be critical to a successful AMF program.

3.7.1 Inventory Tracking System/Asset Management

The inventory tracking system is the information warehouse for all endpoint devices including meters and ERTs, along with CGRs, range extenders, and radios for distribution devices like capacity banks, and FCIs. This system also stores the information on cellular radios for reclosers and large scale ERTs. The cache holds all relevant information necessary to track an end point device across its deployment lifecycle including, but not limited to, device manufacturer, manufacturer date, installation date and location, serial number, warranty information, GIS location of service, maintenance log, and any scanned records. The inventory tracking system also reconciles field crew readers with the back-office systems and has the capability to store records of field crews to scan during any service calls.

3.8 Cyber Security

The Company understands that in an evolving technology landscape, there are growing cybersecurity risks. National Grid and the Energy sector have also seen an increase in cyber related threats to its infrastructure and business operations. The cyber threat landscape has been continuously evolving over the years with an increased sophistication targeting utility operations causing disruption to the safe and reliable services we serve to our local communities. These threats could cause cyber effects such as loss of integrity and availability to the AMI system and range from increased peak usage up to widespread outages.

The National Grid Cybersecurity REV framework in support of the AMF efforts of the Company are to ensure we maintain a reliable and secure electricity and gas infrastructure and ensure the protection needed for the confidentiality and integrity of the digital overlay. The National Grid Cybersecurity REV Framework focuses on implementing a comprehensive cybersecurity plan to ensure adequate protection for both customers and the company. The Framework provides a common language for understanding and managing cybersecurity risk to help identify and prioritize actions for reducing cybersecurity risk. The Framework provides for National Grid to align its cybersecurity activities with its business requirements, risk tolerances, and resources. This framework is guided by and is aligned to the NYS Joint utility Cybersecurity and Privacy framework that has been established by the NY Joint Utility Cybersecurity Working Group.

As part of the framework, cybersecurity and privacy provisions in the form of multiple security services to support AMF deployment will be implemented. These security services will be the cornerstone for any cybersecurity or privacy related component of the overall solution. At a high level, these security services will ensure that proper end-to-end security controls are incorporated into all aspects of design, implementation, and deployment of smart meter technology. These security controls will ensure that all Smart Meter devices, communications infrastructure, and back office systems supporting them, along with user portals and other critical infrastructure are fully secured and monitored. Moreover, the plan will also ensure that any data transmitted across this network is properly protected (e.g. encrypted) using industry recognized standards and protocols.

The service model is layered and the security controls that will be implemented to support a particular security service are based on the "NIST SP 800-53 Rev. 4: NIST Special Publication 800-53 Revision 4, Security and Privacy Controls for Federal Information Systems and Organizations". This serves to assist in providing greater flexibility and agility to defend against an ever changing threat landscape, along with the ability to implement a structured approach to tailor any provisions required to specific missions/business functions, environments of operation, and/or technologies based on the level of risk that is acceptable. The Cybersecurity and privacy controls provide a comprehensive range of countermeasures to mitigate any risks that have been identified for the organization and its information systems due to threats impacting National Grid's plan to meet NYS REV objectives. The controls are designed to be preventative, detective, or corrective and protect the confidentiality, integrity, and/or availability of information. They involve aspects of policy, oversight, supervision, manual processes, actions by individuals, or automated mechanisms implemented by information systems/devices. The security controls are focused on the fundamental countermeasures needed to protect organizational information during processing, storage, and transmission. The privacy controls ensure that privacy protections are incorporated into information security planning. The use of standardized privacy controls provide a more disciplined and structured approach for satisfying privacy requirements and demonstrating compliance with those requirements. The Company will leverage industry-leading best practices to meet the goals of a robust cyber security program. These practices include robust training, change control, configuration management security, access monitoring, incident management, end-to-end encryption, network segmentation, and firewalls, as well as other security controls mentioned above. The cyber security measures outlined will enable National Grid to maintain confidentiality and integrity to the best of its ability in both the short and long term future of AMF.

4 PROGRAM IMPLEMENTATION SUPPORT

4.1 Customer Engagement

AMF is an enabling technology allowing customers the ability to become engaged energy consumers. Particularly, the near real-time energy consumption data can be highly impactful as it allows customers to manage their bills and participate in DR, and EE, and pricing programs. However, in order for the benefits of smart meter technology to be fully realized by the customer, National Grid recognizes the importance of pairing this technology with proactive customer engagement initiatives. Core to a successful smart meter adoption and deployment, in addition to the success of subsequent pricing programs, is a robust and thorough customer centric engagement program. There are three distinct stages that National Grid plans to implement to elevate customer participation:

Stage 1 - Deployment: The purpose of the deployment stage is to initiate a fact based smart meter campaign to inform the public of the benefits associated with AMF and build the foundation to establish trust. This campaign will also articulate fact-based counter arguments to any opposition claims and attempt to decrease overt bias toward smart meter technology. Given the size of the territory and diverse customer base, it is safe to assume that there will be a wide range of smart meter knowledge, opinions, understandings, and interests represented. Pre-existing customer bias has the potential to increase costs and delays throughout the process of smart meter implementation. Therefore, National Grid will reduce these potential costs through dynamic and proactive customer engagement across various forums to set expectations and mitigate concerns.

Stage 2 - Steady State: This stage objective is to increase customer satisfaction through access to specific enhanced data provided by smart meter technologies. Further, this stage aims to reduce customer call volumes by transitioning toward a self-service model. In order to attain these goals, the approach will have to be proactive. Using the associated smart meter systems such as the web portal to provide a host of solutions to anticipate customer needs is an example of this proactive approach. Any reactive interactions with customers must utilize these same systems that provide higher quality and personalized service to drive impactful results. Overall increased accessibility to data and self-service portals will allow customers to become more autonomous and have greater levels of satisfaction. Having a robust interface that seamlessly allows customers to access their data and easily track down any questions they might have will make them less reliant on the call center.

Stage 3 - Program Education/Enrollment: The goal for this step is to educate customers on the opportunities and benefits associated with participation in utility or third-party services and programs. The increased knowledge of opportunities coupled with customer involvement aims to increase customer satisfaction by giving them options to reduce their energy costs.

The diverse customer audience of National Grid, combined with an array of stakeholders representing an assorted set of interests, makes creating dynamic outreach, engagement and education programs essential. This three-stage program will utilize a multi-channel, multimedia campaign that integrates social media to inform and educate energy consumers, ultimately creating a two-way conversation with customers about smart meter technology.

A well-structured plan will increase acceptance, ease implementation, and allow customers to make informed decisions, including participation in innovative pricing programs and other AMI-enabled programs. Ultimately, by readily placing information and data about smart meter into the hands of the customer, National Grid will be able to support customers in realizing the full complement of benefits associated with AMF.

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4.2 Systems Integration

System integration is key to harnessing the full magnitude of smart meter benefits across National Grid infrastructure of devices, software, and systems. Only by enabling meters to exchange data with routers, routers with systems, and systems with other systems is it possible maximize the effectiveness of the overall platform. As such various IT / IS costs associated with system integration were included in the AMF Business Case model. A well-structured approach will include the following:

- Capability analysis and end-to-end definition of functionality at each step;
- Systems Architecture to define data interfaces between systems and components;
- Detailed requirements definition for all systems and interfaces;
- Custom configuration and development of system APIs;
- Detailed test case planning and definition; and
- Careful test execution and defect documentation.

A platform such as AMF will have highly complex data exchanges. Throughout the industry, systems integration is supported by an enabling technology known as an Enterprise Service Bus (“ESB”), which helps facilitate the exchange of standardized data elements between all impacted systems.

In addition to a functional platform, other benefits of strong systems integration include:

- Improved system response time and performance;
- Lower labor costs and increased operational efficiency; and
- Compatibility across system devices and software.

4.3 Process Design

Process design is an extremely important component upon which program development and organizational change depends. Many utility employees will be impacted by the deployment of AMF including meter field technicians, meter shop technicians, customer service reps, control center operators, billing analysts, etc. Each role will be changed to some degree to accommodate the incorporation of this new technology. To aid in a smooth transition for both customers and employees, the definition of how people will use the technologies is just as important as defining what the technologies are capable of doing. A strong process includes:

- **Detailed Definition of System Processes and Requirements:** Conduct workshops with subject matter advisors, vendors, end-users, IS representatives, and other key stakeholders to gather, define, and document business processes for the new systems. These sessions, particularly the ones addressing integrations will uncover additional business, functional, non-functional, performance, technical, data, integration, and transitional requirements;

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- **Process Design and Organizational Impacts:** Create process flow documents to ensure stakeholder agreement to key sequences, activities, and organizational divisions. Refine processes by documenting requirements, inputs/outputs, contemplated customizations, org/change impacts, KPIs, dependencies, business rules, data needs, data flows, automation touch points, reporting considerations, etc.;
- **Tabletop Processes Simulation Testing:** Leveraging key end-user and a variety of sunny-day and rainy-day scenarios, identify and mitigate pain-points of the newly proposed process; and
- **Cross-Workstream Integration:** The business process team will coordinate with downstream teams to ensure full understanding of documented intent for solution architecting, detailed design, and testing.

4.4 Change Management

Change management is an important suite of tools to deliver stakeholder understanding and behavioral changes to support specific business objectives associated with AMF. This methodology is based on the belief that people's reactions and behaviors at different stages of a change process can be predicted, managed, and measured. The key components of National Grid smart meter change approach include the following:

- **Readiness Assessment:** Qualitatively identify key stakeholder groups and conduct workshops to assess their expectations, goals, and understanding of the benefits that a program like this would bring. Quantitatively measure readiness to determine if employees: 1) understand the expected changes, 2) have the right skills for the operational phase of the program, and 3) have any barriers to change. Gather information from training metrics, change network surveys, focus groups, and change tracking surveys to develop monthly dashboards which can help define any change management plan modifications;
- **Business Engagement:** Create a tailored plan of engagement for each user group. The change plan will define the sequence, mix, and pace of change activities to help reduce productivity dips and enhance buy-in across these groups;
- **Business Readiness:** Establish an advisory council to create the organizational readiness scorecards and confirm the appropriate metrics for critical functions impacted. Measure progress, identify issues and actions, and update activities in the change plans to incorporate feedback continually from end users;
- **Organizational Design:** Identify new roles, skill sets, and organizations required to operate the new smart meters, infrastructure, and associated systems and correctly size the balance of work between existing back-office functions; and
- **Transition Plan:** Creation of a knowledge transfer and sustainability plan to identify how various materials (job aids, process flows, etc.) will be transitioned and maintained post deployment.

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4.5 Program Management

Program management is an important set of procedures and processes that help to add robust structure to any large infrastructure implementations. For smart meter deployments of this magnitude, a robust program management governance structure adds a number of valuable organizational tools and protocols to ensure program alignment and compliance with project expectations. Some of the benefits include:

- Delineate a clean authorized decision-making process that will define the project direction and allow the scope to be established and approved;
- Define the operational constraints (budget, time, and scope) as well as the procedural constraints (policies, processes, and standards);
- Respond to input from the projects' Stakeholders typically in the form of responses to issues and risks. The Program will manage issues and change at the Program level, while Project Managers will do the same at the project level. The two will interact to coordinate on items, such as in the escalation of a project issue;
- Monitor activity to confirm the project is complying with the program-level constraints (e.g., milestones, budget, and scope) are on track. Where these activities are at risk of not meeting expectations, ensuring that mitigating actions are taken to address those risks / issues; and
- Ensure compliance with established program criteria and that all of the agreed-upon requirements have been met, de-scoped or deferred. Once acceptance is complete, the program's final responsibility is to ensure that the administrative close of the projects and program are taken through to conclusion.

5 SCOPE AND SCHEDULE

National Grid considered a number of different scenarios that would make measurable progress towards the PSC's AMF vision. In an effort to balance the benefits and costs, National Grid has weighed a number of different options. Each option is scaled to different target populations and examines a set of technologies that could be deployed, necessary supporting infrastructure, interdependencies of these components, public versus private backhaul and potential cross-jurisdictional benefits of splitting back-office systems, among other considerations.

5.1 AMF Deployment Scenarios

As seen in Figure 14, the team has proposed and analyzed three options for the AMF deployment. While the team evaluated a number of different permutations, each of following options represent a deployment philosophy and have a wide range of impacts and implications associated, as well as related benefits and costs that are discussed in greater detail in the following section. To articulate the range of likely outcomes for each deployment option, two

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sensitivity scenarios are presented in the benefit-cost analysis. The key deployment option sensitivity scenarios are summarized as follows:

Sensitivity Scenario 1

- National Grid and National Grid's Massachusetts operating companies share back-office IT/IS costs: Option A: 55%/45% (Upstate New York / Massachusetts), Option B: 42%/57%, and Option C: 15%/85%;
- Time-Varying Rates - Customer participation rates vary among scenarios under an Opt-Out pricing program model: Option A: 80% participate, Option B: 90% participate, and Option C: 100% participate.

Sensitivity Scenario 2

- All back-office IT/IS costs, 100%, are attributed to the Upstate New York service territory for all deployment scenarios.
- Time-Varying Rates achieve 20% participation for all deployment scenarios under an Opt-In pricing program model.

Option	A		B		C	
Description	Full Deployment		Urban Deployment		Dispersed Deployment	
Scenario	1	2	1	2	1	2
MA/NY Back-Office IT/IS Cost Sharing	NY 55%	NY 100%	NY 42%	NY 100%	NY 15%	NY 100%
Pricing Program Participation Rates	80%	20%	90%	20%	100%	20%
Number of Electric Meters*	1.7M		0.7M		0.17M**	
Number of Gas ERTs*	0.7M		0.3M		0.07M**	
Portal Data Presentment	Raw Data viewable within 4 hours, Billing Data in 24 hours					
Field Deployed Technologies	Smart Meters, ERTs					
Enabling Infrastructure	Collectors/relays/routers				Cellular radios on all smart meters	
IT/OT Investments	AMI Head End, MDMS, Data Warehouse, CSS, and other Back-Office Investments					
Initiatives	Web Portal, Green Button Connect, Marketing & Outreach					

***it should be noted that the number of electric and gas ERTs to be replaced includes both active and inactive meters**
****Approximately 10% of electric and gas customers is the steady-state maximum for the opt-in scenario**

Figure 14: National Grid deployment scenarios

There are many characteristics of the smart meter deployment that are similar no matter which option is chosen. The largest of these infrastructure upgrades are the back-office systems. They include AMI Head End, MDMS, Data Warehouse, CSS, and upgrades to other back-office systems to integrate them with the new systems. Additional customer facing elements like the web portal, Green Button Connect My Data, and all the systems to support their functionality will be part of any deployment.

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The primary differentiator between these options is the number of meters to be deployed with options ranging from approximately 10% of all National Grid Upstate New York customers to nearly 100% of metering points across Upstate New York. Remaining divergence between Options A and B and Option C is the enabling infrastructure investment necessary to support the contemplated scale of deployment. Where Options A and B will deploy the communications infrastructure to support a robust mesh network, Option C, with its inherent uncertainties regarding the number, location, density of customer's who opt-in, cannot. All these unknown elements make it hard to justify the expense of building the foundational communication elements that make up the mesh network. To hedge against these uncertainties and efficiently use resources, Option C will utilize cellular radios and a public network to transmit data to the back office systems.

5.2 Approach to Implementation

The proposed AMF implementation timeline is six years beginning in the fiscal year 2019. While the AMF deployment is still being refined at the time of this writing, a broad timeline is as follows. The start date for the project reflects the time required to engage stakeholders following the initial DSIP filing to further develop and refine the plan, and to achieve regulatory approval either separately or as part of a general rate case. The anticipated timing of the filing of National Grid's next electric and gas general rate case is mid-year 2017. Year 1 of AMF implementation includes detailed technology design and the formal procurement process, followed by the installation of back office systems and communication infrastructure. This will be followed by a five-year meter and ERT installation program.

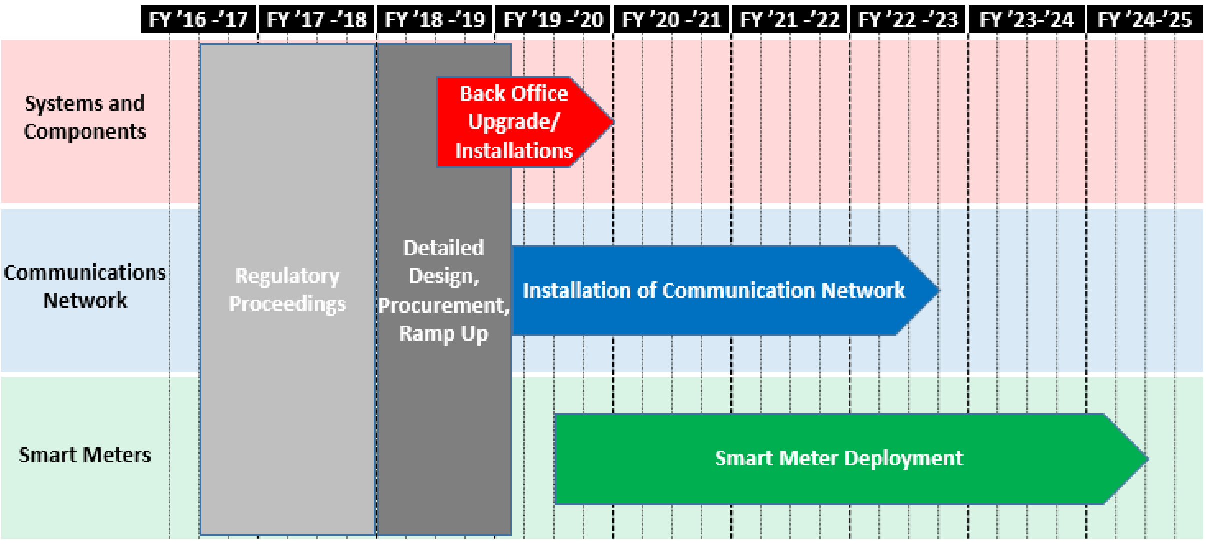

Figure 15: National Grid implementation schedule

With the inherent uncertainties surrounding option C, the staging and deployment timeline is less clear. The number of people that sign up, the cadence of their authorizations, their locations across National Grid's Upstate New York territory, will all have a measurable effect on the timeline. Consequently, additional investigation and scenario analysis will need to be executed if this option is chosen.

6 BENEFITS

The deployment of smart meters, its associated infrastructure and systems is a key step toward achieving the REV objectives. The benefits associated with the AMF Business Case are grouped into three categories: Customer, Societal, and Operational. These benefits will translate into specific features, programs, and offerings, which will continue to evolve over time.

6.1 Customer Benefits

6.1.1 Enabling Programs through Third-Party Access to Data

Smart Meter technology and its associated digital and physical infrastructure form the backbone and foundation of a future energy marketplace. This secure infrastructure will facilitate both customers and approved third-party providers access to interval data. This access to detailed customer data will foster the spirit of innovation in new and creative ways and allow third parties to tailor new products and services to individual consumers. Having a multitude of choices in the energy marketplace will lead to a more informed populace, who is better able to manage their electricity consumption and ultimately leading to customer financial benefits and utility system savings driven by overall system efficiencies.

6.1.2 Enablement of Time-Varying Rates

Smart meter technology will allow National Grid to collect utility customers' energy usage in greater detail than previous technologies would allow. This time-stamped data is the foundation by which any pricing program may be implemented. Time-of-use ("TOU") pricing is when different prices are set at certain intervals during the day (e.g., the afternoon, evening, night, etc.). These price periods are set in advance and only change a few times a year. Critical Peak Pricing ("CPP") is an additional aspect of this program where prices are dynamically adjusted higher during certain operational conditions.

The Business Case considered as a sensitivity an Opt-Out structure where, by default, a large percentage of customers will be enrolled in these pricing programs. Through educational initiatives and pricing signals designed to incent behavior, over time customers will proactively shift portions of their energy consumption to times of day where energy rates are lower thereby resulting in holistic savings.

In additional to incentivizing customers' savings, consumers shifting their energy usage will flatten the overall load curve. This energy time shift, combined with other programs, will lower energy peak, thus reducing capital spend due to peak energy usage and means that higher cost electricity generators will be needed less.

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6.1.3 Enablement of Smart Home Devices

The granular data generated and collected by smart meter technology also benefits customers by enabling smart home devices and giving those consumers greater insight into their energy usage. Eventually, the home energy management system will send and receive secure communications from the utility. Based on the system's programming, it will automatically adjust energy usage with pricing signals and calls for curtailments.

A home energy device enables customers to self-manage their energy consumption. These technologies display consumption information for in-home appliances such as thermostats, water heaters, and HVAC systems, among other devices. Control of usage is remote and may be programmed by the customer to accept curtailment calls by the utility for DR events. The capability is based on smart devices/smart controllers within appliances that are connected via a Home Area Network ("HAN") to a home energy management system.

6.1.4 Enhanced Customer Energy Management and Reduced Consumption

When smart meters have been fully deployed, and the associated back-office infrastructure is in place, customers will have access to their usage data in near real-time, and granularity at sub-hour reading intervals. The frequency of the readings combined with the granularity of the data will enable customers to take control of their energy usage through a number of energy management programs like EE, and DR, in addition to other pricing programs and through access to offerings by third party providers. AMF capabilities will also allow customers to monitor their consumption. This in conjunction with education programs and technical innovation will enable them to make more informed choices, which may lead to a reduction in consumption.

6.1.5 Demand Response Participation

Defining explicit characteristics of National Grid's DR program was not part of this AMF assessment. However, these programs do have certain commonalities which can be contemplated in a generic sense to estimate benefits and costs. DR programs are dependent on customers participating at certain times when needed, with compensation dependent on levels of participation. For certain types of programs, AMF enables participation by allowing bi-directional messages to be sent from the utility to a premise requesting curtailment accompanied by an acknowledgment or confirmation once curtailment has occurred. In other programs, AMF may not include the curtailment notification. In either case, AMF captures interval data for both the DR event as well as corresponding reference intervals which are typically used to measure curtailment performance during events. By capturing this information, it is possible to present performance measures to customers more quickly for internal analysis and budgetary consideration.

6.1.6 Outage Management

Smart meter technology has the ability to report an outage in near real-time. This ability allows the operations center to understand the extent of the outage quickly without the need to rely on customer calls and substation monitoring. The functionality permits the operational system to reach an outage more quickly and dispatch an appropriate number of field personnel to restore power. Furthermore, once power has been restored, smart meters can be dynamically pinged to assess whether the entire outage has been restored or if additional work needs to be done to restore nested outages.

6.1.7 Enhancing Customer Service

AMF data can be used in numerous ways to revamp the customer experience across the spectrum of channels where National Grid and customers interact. Historically, operational information has been somewhat constrained by the limits of technology, but by embracing a philosophy of greater system integration and data presentment, customer satisfaction can be improved.

Call center interactions are the most traditional means of reactive customer interaction between the utility and the customer. Enabling Customer Service agents to have access to more real-time and historical information about the customer experience allows for more impactful information to be shared with customers as well as a more satisfying experience. Some of these capabilities include:

- Real-time pinging of meters to determine if an outage is distribution system related or behind the meter and attributable to customer infrastructure;
- Real-time pinging of meters to determine voltage levels being delivered;
- Real-time reconnects of electric meters as appropriate (due to bill pay, move in, etc.);
- Historical assessments of outage experience (Customers Experiencing Multiple Outages ("CEMI") and other metrics) to give customer representatives context;
- Historical assessments of voltage delivered; and
- Additional rate plans and options which customer service reps can present to customers who are seeking greater flexibility for their energy management needs.

Proactive approaches such as outbound calls / emails, text messaging, and social media posting can also be used to notify customers of various events that will influence their energy consumption experience:

- Outage occurrence and/or restorations;
- CPP events, corresponding characteristics, and price signals;
- DR events and corresponding characteristics; and
- Identification of abnormal usage patterns which could impact resulting bills.

Ultimately, web portal enhancements will put the greatest amount of general and educational information into the hands of customers. It will enable increased access for customers to understand the structure of new rates and provide the ability to change plans as suited to their individual circumstances. Using this channel, customers will be able to access more granular information about their consumption patterns and have the ability to download this data via the standard Green Button Download My Data framework. Customers can use this information directly or possibly in conjunction with third-party providers, to make more informed choices and proactively manage their bills. The portal will also allow customers to set preferences for how and when National Grid will proactively engage with them for the above-mentioned notifications. With these enhanced user systems, in combination with associated call center process design investments National Grid will likely see a small long-term decline in call volume from steady-state.

6.2 Societal Benefits

6.2.1 Greenhouse Gas Emissions Reduction

Smart meter technology will play a crucial role in reducing greenhouse gas emissions. The granular data collected by smart meters will enable a generation of consumers to make more informed decisions regarding their energy usage. By building a platform for customers to monitor their energy usage with a level of detail previously unavailable and making it easier for them to understand how their choices affect energy consumption. Smart meters, in conjunction with education, EE, DR, and pricing programs, will reduce consumption. The decrease in demand will have an associated decrease in greenhouse gas emissions.

Additionally, the granular energy data collected by smart meter technology may be used by third party providers to design innovative products and services. Many of these creative solutions will be designed to maximize EE thereby creating additional energy savings, thus, fewer greenhouse gas emissions.

6.2.2 Reliability Improvement

While smart meters by themselves do not have the same magnitude of reliability benefit as a system where it's integrated with ADMS and FLISR, there is an incremental reliability benefit associated with smart meters as a standalone entity. As previously described, smart meters have the ability to report an outage in near real time. Without FLISR to automatically reroute power to portions of the grid that are not affected by the break, manual intervention by field personnel is still necessary to restore power. However, because of this ability to report an outage in near real time, the operations center quickly knows there an issue and can react appropriately, in essence, shortening the duration of the outage.

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6.3 Operational Benefits

6.3.1 Remote Connect Activities

In circumstances where electrical power has been disconnected for any reason, within minutes of meeting the criteria for restoration, power may be remotely restored, and diagnostics run to confirm power is reestablished and the meter is functioning properly. With the current metering system, customers or potential customers would need to get a slot on the schedule, field personnel would need to be dispatched, and depending on where the meter is located, the affected person may need to be on the premises to let the field technician in.

Remote connect is not allowed for gas meters due to safety reasons.

6.3.2 Remote Disconnect Activities

When a customer requests that their electrical power and/or gas service be turned off (either because they are moving or because it's a seasonal residence), smart meters can be remotely accessed by service center staff who can then disconnect the electricity or gas (if meters are replaced) without the need to dispatch field personnel.

The ability to remotely disconnect customer's electric and/or gas service for non-payment also exists which can reduce certain disconnect costs that might otherwise be incurred without AMF. National Grid will use this functionality in full compliance with current New York Home Energy Fair Practices Act ("HEFPA") regulations.

6.3.3 Remote Meter Configuration

The ability to remotely configure smart meters provides the utility with the capability to push out firmware and software updates, upgrading the meters' functionality remotely from the utility's operations center. Smart meters are initially programmed with software that calculates and stores a number of parameters including service status, usage and power quality, and firmware that defines the functionality. At the time of installation, the software and firmware in the meter are configured to perform a certain set of functions and calculations based on a specific set of services or mandated requirements. However, the functionality and parameters may change over the life of the meter. The remote update capability allows the operations center to update every meter grid in a short period of time without the need to dispatch field personnel.

6.3.4 Theft Detection

Smart meter technology combines greater frequency of readings with sophisticated algorithms to ensure that electric and gas consumption is accurate. These algorithms can detect usage that attempts to bypass the meter and will alert Company personnel. If the discrepancy is proven to be theft, the Company can take action to address the situation, thus minimizing a cost that would normally be socialized across the customer base, thereby saving other customers money.

6.3.5 Enhanced Revenue Assurance

In addition to theft detection smart meters have the ability to detect meter malfunctions. This feature is enabled through greater frequency of interval readings and back-office system algorithms. These malfunctions have in the past also been a source of revenue loss. By using a data-driven approach, National Grid will proactively mitigate these potential sources of power loss and their associated revenue losses, all while minimizing time intensive site inspections to try and detect any meter that might exist.

6.3.6 Workforce Management

Smart meter technology can be programmed to automatically send a power outage notification when power is lost. Where once the operations center personnel had to rely on monitoring substations and receiving customer calls to confirm a power outage, smart meters are able to broadcast, in near real time, their power status. This ability gives the operations center an estimate of the extent of any problem and allows them to better manage the magnitude and cadence of their response. Bi-directional communication with the smart meter also allows the National Grid personnel to ping meters to determine their status, which reduces the need to dispatch field personnel to perform the assessment.

6.3.7 Grid Planning and Load Management

The greater granularity and frequency of information sent back from the smart meters lends itself to a number of insights that were not previously possible due to data limits placed by the level of information available. With this new level of data, National Grid will be able to analyze customer usage to find patterns that will enable grid planning and load management.

From an infrastructure perspective, granular data will give National Grid a better understanding of customer consumption patterns at more frequent intervals. This load data, combined with an infrastructure database populated with detailed equipment profiles, will allow National Grid to evaluate equipment across the board. Transformers, for instance, could be evaluated for loading instances that would affect life expectancy. National Grid would be able to do this because they know its maximum load capacity and can ascertain through a data search whether peak loading conditions surpass those limits.

From a planning perspective, utilities have traditionally estimated load profiles along a circuit utilizing voltage curves and predictions based on feeder head readings. With actual load data from smart meters, National Grid will understand the potential impacts of their infrastructure decisions with a greater degree of certainty. This will allow National Grid to evaluate planning options for maximum impact when looking to connect new equipment. Smart meter data will also enable a fact-based analysis when evaluating the impact of new technology, like DERs, connecting to the grid.

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6.3.8 Voltage Abnormality Reporting

Part of core smart meter technology is the ability to detect and notify abnormal voltage levels. When the voltage falls outside the allowable bounds of electrical service, the meter will report the situation to the real-time control center systems (e.g., ADMS), allowing the Company to proactively investigate and take steps to correct, thereby mitigating potentials problems that stem from power quality issues. With the current meters, customers tend to identify and report electrical power quality abnormalities, typically “dim lights” situations that they are experiencing.

6.3.9 Outage Reporting

An additional benefit of core smart meter technology is the ability to report an outage in near real time. Although individual smart meters are electrically powered, they have enough battery life to signal the network and operational systems of a power loss. This ability has several advantages over the current system of monitoring substations for very large power changes that would indicate an outage and rely on customer calls to pinpoint. Smart meters near real-time power outage notification allow the system operators to assess outage characteristics more quickly, have more extensive situational awareness, and take steps to restore power more efficiently. Furthermore, once power has been restored, smart meters can be dynamically pinged to assess whether the entire outage has been restored or if additional work needs to be done to restore nested outages.

6.3.10 Reduction in Call Center Volume

Smart meter technology and its associated back-office systems enable customers to access their energy consumption data through a secure web portal and applications for smartphones and other portable devices. This ability for customers to interact with their interval data in new and innovative ways, combined with additional customer support system investments, will ultimately impact call center call volumes. While National Grid expects to see a short-term uptick in calls, over a longer period as customers get used to the technology, there will a corresponding decrease in call center volumes. Additionally, improved back-office capabilities will have the ability to detect issues before a customer experiences problems and calls.

6.3.11 Reduction in Bad Debt Net Write Off

Bad debt is incurred when National Grid customers are unable or unwilling to pay their billing obligations. National Grid makes every reasonable attempt to collect those outstanding bills. Eventually, this unrealized revenue is classified as a loss and is written off and spread across all customers. Smart meter’s ability to remotely disconnect service, within the existing approved parameters, will reduce these socialized costs. Although the smart meters cannot entirely eliminate bad debt write-offs, the remote disconnect function can reduce the period between when an electric customer defaults on payment to when their meter is actually disconnected, thus reducing the loss incurred. In time the impact of this functionality will prompt a change in customer behavior, resulting in a significant reduction in overall bad debt and operational expense. This will improve the customer experience due to fewer collection activities such as mailings, phone calls, and field visits.

6.3.12 Reduction in Inactive Use Costs

The ability of Smart Meters to remotely connect and disconnect drive benefits that result from costs associated with inactive meters or soft off unoccupied premises. National Grid estimates that there are regularly around 170,000 inactive electric meters. A soft off inactive meter with use occurs when electric services are used while the linked account is inactive. For instance, if a customer moves into a previously unoccupied property without notifying the company to change the account name, use on that account will not be billed until the meter is read and use is discovered. The company then investigates to start a new account. The interim period of time between inactive meter activity and confirming a new account name can rarely be billed as the actual consumer cannot be fully verified. The ability of smart meters to quickly sense usage and be remotely disconnected without an employee needing to enter the dwelling minimizes inactive meters usage on vacant property. Resultantly, National Grid can reduce these unbillable energy costs that were previously disseminated across the entire customer base.

6.4 Additional Synergies/Coordination Benefits

The components, capabilities, costs, and benefits articulated in earlier sections all align to the core vision of AMF for potential near-term implementation. Other capabilities and use cases were also contemplated but were determined to be out of scope. As such, no costs or benefits have been defined for these capabilities. However, as AMF deploys, stabilizes, and matures, the preliminary vision can be expanded upon in the following ways.

6.4.1 Water Utility/Municipality Revenue Opportunities with Joint Use

Electric utilities have pursued the concept of "Joint Use" for many years through the use of shared infrastructure like utility poles that support electric, telephone, and cable television lines. Applied to metering technology, the technical umbrella of National Grid's proposed AMF infrastructure could be leveraged to support the metering efforts that overlap with water utilities. While water meters themselves could likely be procured and installed by the respective water agency, wireless radios, backhaul, and back-office validation systems could be owned by National Grid but provided as "Metering-As-A-Service" to interested jurisdictions. In this way, while REV is strictly applicable to energy, the concepts of greater customer information and empowered decision making can be expanded as a more holistic capability for customers located in Upstate New York.

6.4.2 AMI for Streetlights

Many metering technology vendors offer metering capabilities for streetlight infrastructure which complement other metering capabilities. Typically, streetlights have a standard receptacle for a photoelectric controller to turn the light on and off at night. This module can be replaced with a dedicated AMI streetlight meter. At a minimum, this module integrates with the legacy metering mesh and provides additional nodes for stronger data routing. Further, by virtue of the inherent elevation, the additional nodes can also reduce communication hop counts by increasing the number of direct communications to the nearest wireless router.

Streetlight AMI also has several benefits independent of the broader metering platform. These include:

- Identification of bulb outages to ensure that lights are providing sufficient illumination for safety;
- Identification of “day burners” to reduce bills and increase EE;
- Possible new rates and services offered to municipalities for enhanced information and customer choice; and
- Combined with LED bulb deployments, lights can be dimmed to further optimize EE.

7 SCENARIO SUMMARY

The results of the AMF Business Case analysis are found below in Figure 16. The analysis was performed in alignment with the New York Public Service Commission’s recent Benefit-Cost Analysis (“BCA”) Order.

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20-Year NPV ($ in Millions)		A: Full Deployment		B: Urban Deployment		C: Dispersed Deployment	
Number of Electric Meters		1.7M		0.7M		0.17M	
Number of Gas Meter ERTs		0.7M		0.3M		0.07M	
MA/NY Back-Office IT/IS Cost Sharing		NY 55%	NY 100%	NY 42%	NY 100%	NY 15%	NY 100%
Pricing Program Participation Rates		80%	20%	90%	20%	100%	20%
Scenario		1	2	1	2	1	2
Benefits	SCT Benefits	603.22	451.46	248.09	193.56	143.77	84.69
	UCT / RIM Benefits	467.54	339.77	195.39	145.33	131.45	73.81
Costs	Capital – Full AMF	382.77	392.21	185.55	197.75	73.37	91.53
	Capital – AMR Replacement	(110.15)	(110.15)	(43.89)	(43.89)	(15.67)	(15.67)
	AMF Net Capital Expenditures	272.62	282.06	141.66	153.86	57.80	75.86
	Operating Expenditures	147.85	168.94	106.08	133.33	150.35	190.67
	SCT Costs	420.47	451.00	247.74	287.20	208.16	266.53
	UCT / RIM Costs	420.47	451.00	247.74	287.20	208.16	266.53
SCT Ratio		**1.43**	**1.00**	**1.00**	0.67	0.69	0.32
UCT / RIM Ratio		**1.11**	0.75	0.79	0.51	0.63	0.28
Est. Monthly Customer Impact (per meter)[5]		$ 2.37	$ 2.49	$ 3.04	$ 3.41	$ 9.25	$ 11.58

Figure 16: Benefit-Cost Analysis

7.1 AMF Benefits

Figure 17 highlights the broad BCA benefit categories deemed relevant to AMF deployment in National Grid's Upstate New York service territory. The Figure displays only Option A – Full Deployment benefit components, as it is the only deployment case evaluated that passes the BCA defined SCT, UCT, and RIM.

[5] The Estimated Monthly Customer Impact is a value calculated to provide an understanding of how the basic service fee of Upstate New York customers would reflect National Grid's AMF investment. The dollar per meter value derived for each Option and corresponding Scenario does not reflect a customer class allocation. The value is calculated by (1) present valuing an estimated revenue requirement stream calculated for the 20 year business case timeline, (2) translating the NPV revenue requirement into a levelized annual payment, and (3) distributing the levelized revenue requirement to the in-scope electric and gas meter count on a monthly basis. The initial revenue requirement stream is calculated in accordance with PSC Case No. 12-G-0202 / E-0201, Rate Year Ending March 31, 2016 methodologies.

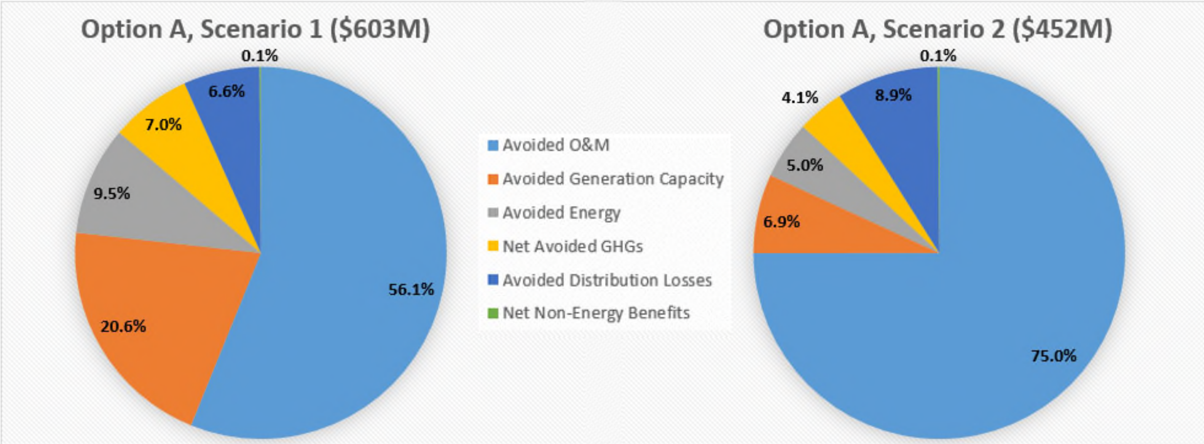

Figure 17: AMF Business Case Benefits Components for Option A

The remote metering and communication capabilities of AMI meters and ERTs provide a variety of opportunities for Avoided O&M benefits, the largest benefit category realized by the AMF Business Case. Avoided O&M savings are the direct result of data-driven decision-making by both the utility and the customer. Three subcategories, reduction of meter inspections, remote metering capabilities, and improvement in bad debt write-offs, make up approximately 90% of Avoided O&M savings. These savings come when labor and vehicle resources are reduced because on-premise visits are no longer required to investigate, connect or disconnect a meter after the proper customer contact process has been performed. In addition, data granularity and remote disconnect capabilities together improve debt collections and reduce the Company's net write off expense.

The AMF Business Case identified the majority of AMF benefits to be a result of Avoided O&M expenses, but it is important to note that the amount of Avoided O&M benefit changes very little from Scenario 1 to Scenario 2. Varying the Opt-Out vs. Opt-In customer participation in pricing programs accounts for the majority of the difference in benefits realization between Scenario 1 and Scenario 2, affecting Avoided Generation Capacity, Avoided Energy, and Avoided Greenhouse Gasses categories.

In Scenario 2 customers must choose to participate in a time varying rate program. Based on the experience of other U.S. utilities an Opt-In program will have a number of inherent restrictive factors that will ultimately limit customer participation rates despite the Company's best efforts. This participation rate will thus define the opportunity for reducing electric peak load and energy consumption. The maximum adoption of for pricing programs over a 20 year period falls from 80% in Option A, Scenario 1 to 20% in Option A, Scenario 2. Option A, Scenario 1 in contrast assumes that an Opt-Out program will be employed and that by default far fewer customers will leave the pricing program. Especially if they are already educated to interpret price signals and bill statements through National Grid's three-prong customer engagement strategy and investment.

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7.2 AMF Costs

Figure 18 highlights the major cost components of the AMF Business Case. Again, only Option A – Full Deployment, across a 20-year time horizon, was considered because it passes all BCA tests.

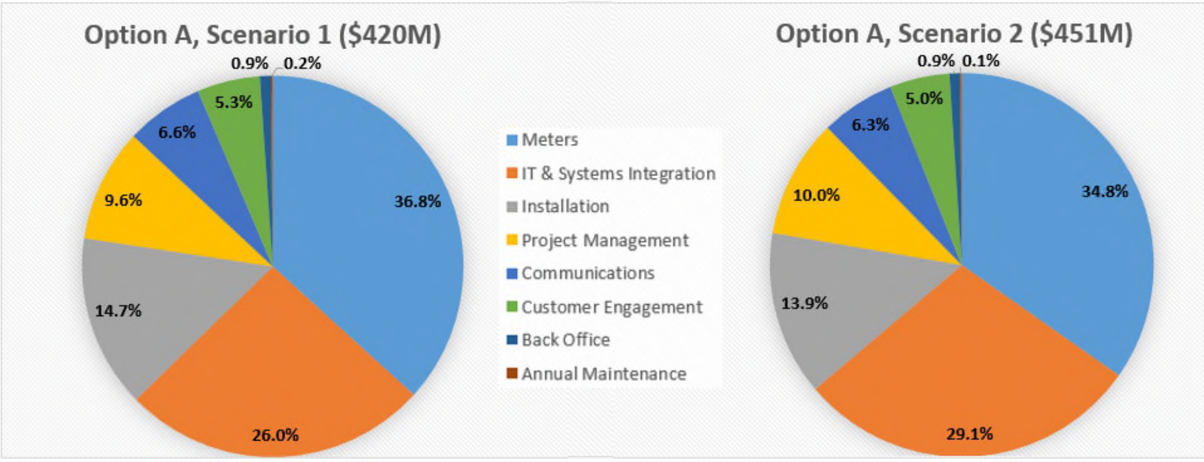

Figure 18: AMF Business Case Cost Components for Option A

Each cost category takes into careful consideration the deployment and on-going expenses necessary to deploy smart meter and ERT technology, along with its associated infrastructure and systems across the Upstate New York territory. IT and Systems Integration costs, as well as Customer Engagement and Program Management costs, begin in advance of the meter equipment deployment to ensure that the system is up and running smoothly when AMI technology is being deployed and that customers understand and realize the benefits of AMI technology.

In both scenarios, electrical meter and ERT equipment and installation together account for over half of the AMF cost. The software, labor, hosting services and analytics capabilities included within the IT, and Systems Integration costs portion contribute over one-quarter to the total cost. It should be noted that the AMF Business Case considers only the AMF costs above and beyond the baseline AMR replacement.

7.3 Potential Areas for Further Cost Reductions

In order to recognize the dynamic nature of such a large scale AMF program and account for an appropriate degree of cost uncertainty, the following section outlines areas worthy of further review and enhancement as National Grid progresses AMF business plans.

- **Meter Purchase Volume Discount:** Costs per meter in this assessment have been calculated based on vendor-supplied estimates. These vendor costs were mostly in line with those of National Grid's Massachusetts affiliate Grid Modernization efforts. However, in both jurisdictions, various options were under consideration; upon final regulatory guidance and clarity of scope, costs could potentially be further refined.

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- **MDMS License and Maintenance:** Costs per meter in this assessment have been calculated based on vendor proposals in response to National Grid's Massachusetts Grid Modernization efforts. These costs have been prorated as appropriate to the characteristics for Upstate New York. However, in both jurisdictions, various options were under consideration; upon final regulatory guidance and clarity of scope, costs could potentially be further refined.
- **Workforce efficiency gains:** As the AMI meter and ERT installation begins, there will be a learning curve for workers in the field. As service representatives get more accustomed to the tasks involved in electric meter and gas ERT installation, they will refine the process, building a portfolio of best practices and learnings that will eliminate many inefficiencies. If the sequencing allows and depending on factors like the nature of the workforce, the speed of the work, the supply chain, etc. it may be possible to reduce some capitalized labor costs and recognize benefits earlier based on an expedited deployment schedule.

8 BCA ANALYSIS

8.1 BCA Tests

To facilitate a comprehensive analysis of the benefits and costs of deploying AMF, the BCA[6] Whitepaper outlines three distinct tests to be included in the BCA results: SCT, UCT, and RIM. These tests are recommended to help evaluate each potential deployment approach from a variety of standpoints. Each of the tests attempts to address the complexities involved in large scale investments with a unique understanding of how utility expense translates into tangible savings and improvement for all impacted parties. Figure 19 displays the results of the BCA evaluation based on the deployment options and scenarios analyzed.

	Scenario 1			Scenario 2		
Option	SCT	UCT	RIM	SCT	UCT	RIM
A	**1.43**	**1.11**	**1.11**	**1.00**	0.75	0.75
B	**1.00**	0.79	0.79	0.67	0.51	0.51
C	0.69	0.63	0.63	0.32	0.28	0.28

Figure 19: AMF Business Case BCA Tests

The primary purpose of the RIM test is to provide an indication of how AMF will affect customer rates. The primary purpose of the UTC is to test the net change in utility system costs and indicate the impact of AMF on average customer bills. The final, and most comprehensive test, is the SCT. The primary purpose of the SCT is whether there will be a net reduction in societal costs. The benefit and cost calculations for the three tests have many overlaps. In fact, as may

[6] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) ("BCA Order").

be seen in Figure 19, the RIM and UCT benefit calculations are the same and capture price reductions that result from load reduction as well as avoided distribution system costs. The costs of the RIM and UCT overlap with the exception of lost utility revenue factoring into RIM. The AMF case does not account for the impact of DERs and the lost revenues that would be a result. The SCT includes many of the same benefits as the RIM and UCT but is calculated considering benefits associated with greenhouse gases and dismissing theft and tampering distribution loss reduction as a pass through to society.

The BCA Whitepaper as approved by the BCA order further outlines that the utility weighted average cost of capital ("WACC") should be used as the discount rate across all metrics. The reason for using a uniform discount rate is that the cost of a utility expenditure plan is absorbed by ratepayers. National Grid's analysis used the after-tax WACC.

8.2 Sensitivity Analysis

The baseline implementation scenario was evaluated for the following sensitivities. This analysis serves to define the order of magnitude of potential change the Option A, Scenario 1 could experience pending regulatory outcomes and utility business and operations decisions.

8.2.1 Key Sensitivities Considered

The following topics were identified as areas where additional analysis could be pursued to potentially have greater confidence in the results articulated.

- **New York/Massachusetts Cost Sharing**: A foundational assumption for cost calculations is that IT and System Integration costs for AMF capabilities can be shared between New York and Massachusetts. However, if the Massachusetts Grid Modernization is not approved, New York customers will need to support all costs associated with the programs and their management.
- **AMF/DSIP Cost Sharing**: There are certain costs that are shared with the DSIP filing. These cost buckets, such as the cyber security, and certain IT and System Integration costs like the Enterprise Service Bus ("ESB"), Information Management & Advanced Analytics Capabilities, Cloud Hosting/ Computing/ Storage to support Data Lakes, Meter Data Management System and Head End system *hosting* capabilities are currently divided by the level of usage of these filing elements. If the AMF were approved and elements of the DSIP were not, these shared elements would need to be fully supported by AMF.
- **Meter Deployment Opt-Out**: Meter deployment opt-out is an area with large potential variability due to the uncertainties associated with the public perception of smart meter technology, among other factors. National Grid's affiliate has seen opt-out rates approaching six percent during the Worchester, Massachusetts pilot; however, given the circumstances of the pilot and the relatively small sample size, it is unclear whether this percent should be included in the range or considered an outlier. The experience of

other U.S. utilities, including National Grid's AMR deployment, show opt-out rates as low as one percent. The sensitivity of opt-out rates is applicable to Options A and B and is recorded at two percent AMI meter and ERT opt-out.

- **Pricing Program Opt-Out Rates**: The deployment of AMI meters will be accompanied by new rate structures. These programs do not mandate customer participation, and can be deployed as Opt-In (with approximately 20% participation anticipated) or Opt-Out (with approximately 80-100% participation anticipated). Benefits are significantly more impactful with an Opt-Out approach, but the approach has not been approved by the PSC. The option is to be evaluated further as part of the ongoing Track 2 component of the REV proceeding and utility-specific filings.
- **Real-Time Communications**: Baseline functionality assumes that data will be collected every four to six hours for electric meters, with the collected information available for customer review within four hours (as raw data only); meter data will be validated and transformed to billing quality data within 24 hours of the end of the interval. The metering / billing infrastructure can be enhanced to have partially validated billing quality data available within four hours of the end of the interval, where available, accompanied by billing quality in 24 hours. The faster turnaround would require additional communications and back-office data processing.

8.3 Sensitivity Analysis Results

Figure 20 displays the results of our sensitivity analysis. Note that this analysis is based on Option A, Scenario 1. In each analysis, a single variable is being isolated and varied from its parameters in Scenario 1 to the appropriate contrasting state.

Sensitivity	BCA Impact	Increase/ Decrease	Cost/Benefit Change
AMI Meter Deployment Opt-Out	Benefit	Decrease	$19.3M
	Cost	Decrease	$11.5M
Participation Methodology for Pricing Programs (Opt-In vs. Opt-Out)	Benefit	Decrease	$151.8M
Back-Office Cost Sharing (NY & MA)	Cost	Increase	$16.5M
Real-Time Communications	Cost	Increase	$6.3M
AMF / DSIP Cost Sharing	Cost	Increase	$85.4M

Figure 20: AMF Business Case Sensitivity Analysis

9 CONCLUSION

The BCA Order's SCT, UCT and RIM support the pursuit of Option A, Full AMF Deployment across National Grid's electric and gas service territory. The cost for systems that allow smart meters and ERTs to be brought online declined marginally as the number of meters and scope of deployment decreases from Option A to C. As such Option A, Full Deployment spreads those consistently large costs out over the largest group of customers, making it the most economical on a per metering point basis. Beyond the economics, there are a number of intangible benefits associated with AMF, the most important being the ability to put National Grid on the path toward achieving REV goals, positioning National Grid to help usher in an energy future for the benefit of its customers, the distribution system and the State of New York.

Exhibit __ (AMI-2)

Updated AMI business case and BCA dated April 28, 2017

Electric and Gas

Advanced Metering Infrastructure

Business Case

For

Niagara Mohawk Power Corporation d/b/a National Grid

April 28, 2017

Table of Content

1 INTRODUCTION

1.1 U.S. and New York AMI Overview

Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid" or the "Company") proposes full service territory deployment of Advanced Metering Infrastructure ("AMI") to include electric and gas smart meter technology, as well as supporting infrastructure and systems. Such deployment builds the foundation to support fundamental change in the energy future of the Company's customers, the electric and gas distribution system and the State of New York. By investing in AMI, National Grid will be taking a key step toward achieving the "Reforming the Energy Vision" ("REV") objectives discussed in the Public Service Commission's ("Commission") Order Adopting Regulatory Policy Framework and Implementation Plan[1] and enabling the Company to assume the role of the Distributed System Platform Provider ("DSP"). These objectives include:

- Empowering greater customer control over energy usage through participation in demand response ("DR"), energy efficiency ("EE"), and pricing programs;
- Allowing granular electric and gas consumption data to be available to customers and approved third party vendors in a timely and efficient basis;
- Providing customers access to a marketplace, and the ability to choose new and innovative energy solutions from vendors; and
- Increasing grid reliability and resiliency.

AMI is a necessary component of grid modernization that builds the foundation to support fundamental change in the energy future of customers. National Grid is implementing AMI to provide its customers with the knowledge and tools to better inform their energy decisions and help them reduce their energy costs. At the same time, AMI will modernize the Company's systems enabling improved delivery system planning, operations, and the integration of increasing levels of distributed energy resources ("DER"). This will support a cleaner, more resilient and reliable, and efficient system consistent with the Commission's REV objectives and the State's clean energy goals. AMI will also provide the infrastructure and capabilities necessary to support the development of distribution markets and their integration with wholesale markets as part of the Company's role as the DSP.

AMI is a proven technology that has now been implemented in the majority of households within the United States. Following are statistics (and supporting Figure 1-1) from a recent Institute for Electric Innovation (IEI) report[2] demonstrating the increasing and prevalent nature of AMI deployments:

[1] Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).
[2] IEI Report, *Electric Company Smart Meter Deployments: Foundation for A Smart Grid* (issued October 2016)

- Electric companies installed 65 million smart meters, covering more than 50 percent of U.S. households, as of year-end 2015;
- Deployments were projected to reach 70 million smart meters by the end of 2016 and 90 million by 2020; and
- More than 30 electric companies in the United States have fully deployed smart meters.

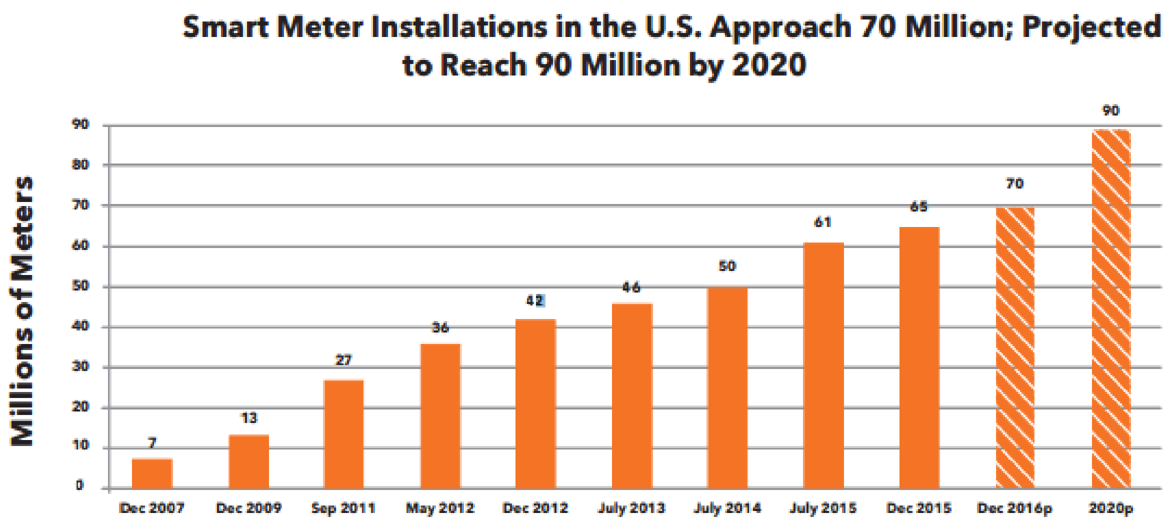

Figure 1-1: AMI Deployments Projected to Reach 90 Million by 2020

In the Supplemental DSIP filed by the Joint Utilities on November 1, 2016 in Case 16-M-0411, all but one of the Joint Utilities indicated that full AMI deployment was foundational for their respective DSPs. The Commission recently approved Consolidated Edison’s AMI proposal and is currently considering petitions filed by New York State Electric and Gas and Rochester Gas and Electric, and Orange and Rockland to implement AMI. The timing of National Grid’s AMI proposal is driven by similar business considerations of the other New York utilities and will provide its customers with access to the same AMI benefits approved, or proposed, for other customers within the State. The timing will also permit National Grid to benefit from technological maturity, competitive pricing, and lessons learned from the other New York utilities with deployment schedules a few years in advance, thus reducing the overall risk profile of the Company’s deployment.

National Grid has determined full smart meter deployment offers more benefits, and as a result a better benefit-cost outcome than other metering solutions evaluated and supports the current and future needs of its customers. Also, as discussed further in the subsequent sections of this business case, AMI deployment is expected to generate a wide variety of benefits. For the purposes of this business case, the Company has elected to focus on the more tangible, quantifiable benefits and compares these with the costs to achieve through AMI deployment and customer programs enabled by AMI. It is fully anticipated that incremental and potentially large benefits could be experienced in areas that are less tangible and quantifiable (e.g. market animation).

1.2 National Grid Current State Characteristics

1.2.1 Customer Characteristics

National Grid's Upstate New York service territory spans more than 25,000 square miles and supports approximately 1.6 million electric and more than 640,000 gas metering points, with dual fuel customers totaling around 590,000. These numbers exclude electric and gas accounts that have been inactive for greater than one year. The service territory is not contiguous, and it spans from the eastern to western to northern borders of the state as shown in Figure 1-2 below. Customer density also varies significantly throughout the service area from dense urban to very rural.

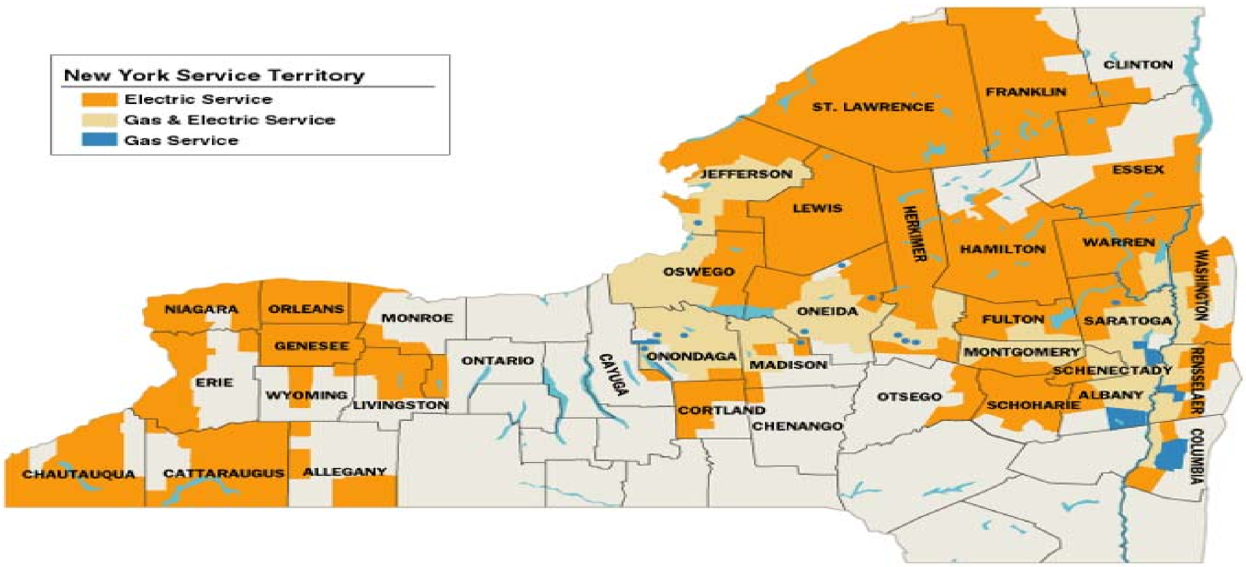

Figure 1-2: National Grid's Upstate New York Service Territory

1.2.2 Existing Metering, Communications and IT Systems in Service Area

The vast majority of electric and gas meters throughout the Upstate New York territory use Automated Meter Reading ("AMR") technology. The electric meters and gas encoder receiver transmitters ("ERTs") were originally deployed in a major program between 2002 and 2004. AMR monthly reads are acquired through radio frequency collection. These collections are done by a fleet of company service vans which drive along routes to allow communication with each meter. The electric meters and gas ERTs are scheduled for replacement beginning in fiscal year 2021 based on their operational life expectancy.

In addition, a small number of larger wholesale customers and retail customers have interval meters, which currently communicate through public cellular connections or through wireless internet protocols.

1.3 AMI Deployment Timeline

The Company proposes a five-and-a-half year AMI program implementation as illustrated in Figure 1-3 below. Over the year-and-a-half period beginning in the middle of fiscal year 2019 and extending through fiscal year 2020, the Company will complete the design, procurement and back-office systems installation phase of the project. During this phase the Company will staff a project management organization and conduct a formal design and procurement process that will involve the development of a detailed customer engagement plan, system requirements including integration, process design, change management program, and meter deployment plan. The Company will use its procurement process to select software, equipment, and support vendors for the program.

Following design and procurement the back-office information technology systems and communications infrastructure will be installed. This will involve building and testing the end-to-end solutions, development of procedures and training materials, organization implementation, including training of field and office personnel, development of communication materials, and initiation of meter deployment communications.

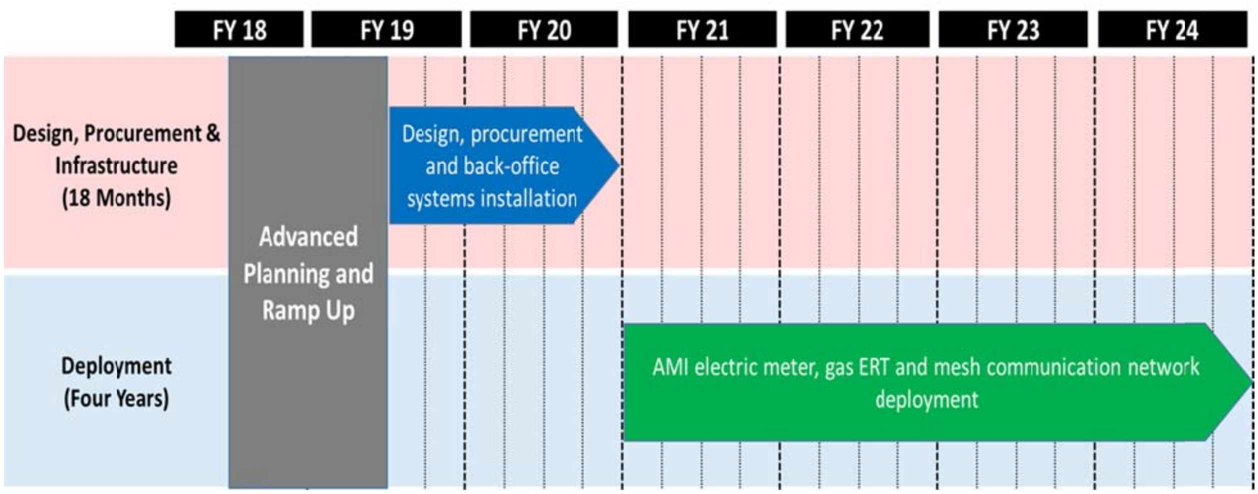

Figure 1-3: National Grid AMI Program Implementation Schedule

In fiscal year 2021, the Company will begin a four year deployment of the AMI electric meters, gas ERTs and the mesh communication network that is estimated to be completed in fiscal year 2024. The Company estimates that approximately 20 percent of electric meters and gas ERTs will be installed in the first year of deployment, followed by 30% in each of years two and three, and 20% in year four of the deployment period as shown in Table 1-1.

Table 1-1: National Grid's Meter Implementation Plan

	FY21	FY22	FY23	FY24
Electric Meters	20%	30%	30%	20%
Gas ERTs	20%	30%	30%	20%

1.4 Deployment Period Capital Expenditures

Capital investments in the first five-and-a-half years (to include full electric meter and gas ERT deployment) are estimated at approximately . The deployment period capital spend does not include the cost of the AMI head-end and meter data management systems that are assumed to be provided under a software as a service (SaaS) arrangement. Deployment period capital investment and cost per meter is included in Table 1-2 below. To support cost per meter benchmarking against other utility deployments, a second scenario that reflects the capitalization of the SaaS payments is included in the table.

Table 1-2: AMI Deployment Period Capital Investment

	Deployment Period Capital Investment ($M)	Number of Meters	Cost/Meter ($)
Electric			
Gas			
Total			
With Head-end and MDM SaaS payments Capitalized			
Electric*	$447.76	1,691,959	$264.64
Gas*	$130.45	642,231	$203.12
Total*	$578.21	2,334,190	$247.71

*- Head-end and MDM expense payments discounted to 2019 dollars

2 CUSTOMER BENEFITS AND REV OBJECTIVES

Under an AMI-enabled future, the relationship between National Grid and its customers will be completely transformed. Customers will have access to new products and technology, and will be incentivized to actively participate in energy markets, manage their energy consumption, and control costs. With the appropriate data systems and web presentment in place, customers will be able to leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions. At the same time, AMI will modernize the Company's systems enabling improved delivery system planning, operations, and the integration of increasing levels of DERs. Together this will support a cleaner, more resilient and reliable, and efficient system consistent with the Commission's REV objectives and the State's clean energy goals.

2.1 Customer Benefits

Table 2-1 below describes the customer benefits the Company expects to be provided or enabled by AMI. These benefits align to NY State's energy policy and NY REV proceeding objectives as described in the next section below.

Table 2-1: Description of Customer Benefits

Customer Benefit	Description
Enhanced Customer Energy Management and Reduced Consumption	When AMI meters have been deployed and the associated back-office infrastructure is in place, customers will have access to their usage data in near real-time, with granularity at sub-hour reading intervals. The frequency of the readings combined with the granularity of the data will enable customers to take control of their energy usage through energy efficiency, conservation, and demand response programs. AMI will also allow customers to monitor their energy consumption through new solutions being proposed in the Company's rate filing (e.g., Green Button Connect My Data and Energy Insights Portal) that will allow customers to better manage their energy bills.
Third-Party Programs and Offerings	AMI will facilitate the creation of a future distribution marketplace as well as access to the wholesale power market. Interval data collected by AMI can be shared between customers and authorized third-parties. This allows for the development of new, innovative third-party products and offerings that can be targeted to customers' individual energy needs. The interval data will also support participation in the NYISO hourly wholesale markets. Having a number of choices in the energy marketplace is anticipated to increase customer awareness and participation, resulting in cost saving products and reduced overall energy consumption.
Innovative Rate Design Options	AMI lays the foundation for innovative rate design structures that can reward customers for optimizing their energy usage (e.g., time of use rates and critical peak pricing programs, "Smart Home" rates).
Enablement of Smart Home Devices	AMI will allow customers to manage their energy consumption through use of smart home devices such as thermostats, water heaters, and other appliances that can be integrated with AMI. Home energy management systems will be able to send and receive secure communications from the Company or third-party market entities. Based on the customer's preference, the system can automatically adjust energy consumption in response to pricing signals and calls for curtailment.
Outage Management	AMI has the ability to report a customer outage in near real-time, without the need to rely on notification from a customer or substation monitoring. Earlier notification of an

Customer Benefit	Description
	outage may speed restoration of service. The functionality also allows the Company to send a signal to AMI meters to identify areas that still require restoration and confirm when all outages have been restored. The Company expects to explore this new capability in the future once the meters have been fully deployed.
Customer Service Enhancements	AMI data can be used by call center representatives to enhance customer interactions. For example, AMI will: allow call center representatives to send a signal to the meter to determine voltage levels or whether an outage is due to customer-owned equipment; allow for real-time reconnects of electric meters; provide historic information about prior outages and voltages; provide for additional rate plans and options for customers seeking flexibility for their energy management needs.

2.2 REV Objectives

REV and other REV-related proceedings are focused on transforming New York's retail electricity market and its energy efficiency and renewable energy programs. The vision of REV is a cleaner, more affordable, more modern, and more efficient energy system across the state of New York. For utilities, these gains are manifested through six primary objectives:

- Empowering New Yorker's to make more informed energy choices and providing them the tools and insight to manage energy usage effectively;
- Animating a consumer energy market environment for third-party energy solution providers to attract and deploy capital and create new business opportunities;
- System-wide efficiency gains by operating more effectively across all aspects of the grid including generation, transmission, and distribution;
- Greater fuel and energy diversity by supporting a broad range of renewable and EE initiatives and reducing soft costs and other market barriers;
- System reliability and resiliency improvements through the integration of DERs into the grid during both 'blue sky' days and significant system events; and
- Cutting Greenhouse Gas Emissions 80% by 2050.

By investing in AMI, National Grid will be taking a key step toward achieving the REV objectives as well as enabling the Company to assume the role of DSP. In this role, the Company will construct, operate, and maintain highly integrated technology platforms, allowing the incorporation of third-party owned DER, which can include DR, EE, storage, and on-site generation. These technologies will be tightly integrated into the Company's distribution infrastructure. Ultimately, enhanced monitoring and control of these resources may support the establishment of a marketplace where commodities from these resources can be exchanged between Energy Service Companies ("ESCOs"), aggregators, customers, and other interested parties.

3 PROGRAM IMPLEMENTATION

The Company proposes a five-and-a-half year AMI program. The first year-and-a-half will serve to address detailed design and procurement along with back-office systems installation. This phase will then be followed by a four year deployment of meters and field area communications, beginning in fiscal year 2021 and ending in fiscal year 2024. Activities within and across these phases are discussed in further detail below and illustrated in Figure 3-1.

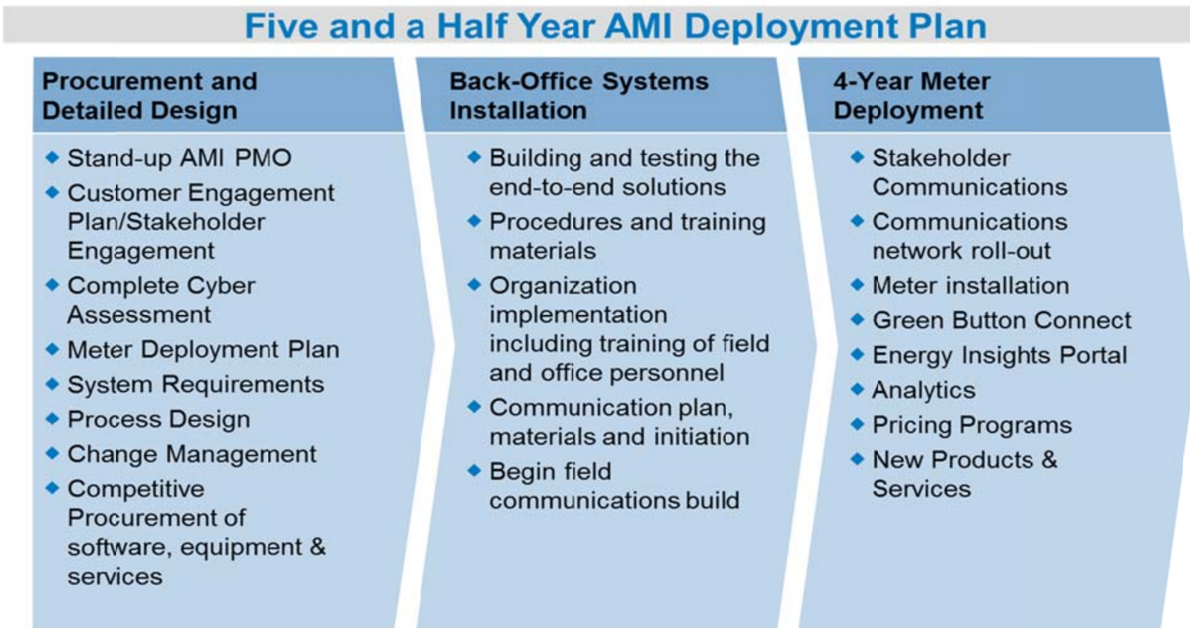

Figure 3-1: National Grid's Programmatic Implementation Approach

3.1 Program Management and Governance

Program management is an important set of procedures and processes that National Grid will need to "stand up" and will help to create the necessary structure during mobilization and execution of the Company's AMI plan. For smart meter deployments of this magnitude, a robust program management governance model is a fundamental requirement to manage program alignment and compliance with project expectations. Benefits of having a robust framework include:

- Clear delineation and authorized decision-making to define project direction and allow scope to be established and approved;
- Definition of operational constraints (budget, time, and scope) as well as procedural constraints (policies, processes, and standards);
- Issue resolution and risk mitigation while leveraging project stakeholder input. The Program will manage issues and risks at the programmatic level, while Project Managers will do the same at the project level. The two will interact to coordinate on items, such as the escalation of a project issue;

- Activity monitoring to confirm the project is compliant and on track with program-level constraints (e.g., milestones, budget, and scope); and
- Assurance of compliance with established program criteria and that all agreed-upon requirements have been met, or properly de-scoped/deferred. Once acceptance is complete, the program's final responsibility is to ensure the administrative close of projects and program is adequate.

Project management will be implemented through regular program level and project team meetings, in which performance will be reviewed and corrective action taken as required. The program leadership team will consist of the major functions and departments engaged in the project and will provide an opportunity for clear internal communications and feedback. This team will provide overall project oversight and will make any decisions that have a significant impact on the budget or schedule.

Risk management is a key feature of the governance framework. A risk register will be maintained at the program and project level to provide necessary auditing and oversight of the entire program throughout implementation. The risk register will be reviewed on a regular basis by the project teams and program leadership team and will be reported periodically to the Commission. The Company will establish a regular cadence of meetings with PSC Staff to provide program status updates.

3.2 Customer and Market Engagement

The Company recognizes the importance of pairing AMI with proactive customer and market engagement initiatives. A detailed customer engagement program will be developed with stakeholder input during the first year of the project. The program will be guided by the staged approach the Company has implemented and gained experience with as part of its Clifton Park smart meter demonstration project and its sister affiliate's experience with a smart meter pilot in Worcester, Massachusetts. Technology solution initiatives will also be implemented to enhance AMI data access, to provide education and energy management insights, and to connect customers with new product and service offerings. These solutions will be in place prior to meter deployment so that customers can begin to immediately realize the benefits of AMI.

There are three distinct stages that the Company plans to design and implement:

> Stage 1 - Deployment: The purpose of the deployment stage is to initiate a smart meter campaign to inform the public of the benefits associated with AMI. Given the size of the territory and diverse customer base, it is safe to assume that there will be a wide range of smart meter knowledge, opinions, understandings, and interests represented. Pre-existing customer bias has the potential to increase costs and delays throughout the process of smart meter implementation. The Company will work to reduce these potential costs through dynamic and proactive customer engagement across various forums to set expectations and mitigate concerns.

Stage 2 - Steady State: This stage objective is designed to increase customer satisfaction through access to specific enhanced data provided by smart meter technologies. To attain these goals, the approach will have to be proactive and leverage engagement technology solutions such as the Energy Management Portal and Green Button Connect My Data described in detail below. Any reactive interactions with customers must utilize these same systems that provide higher quality and personalized service to drive impactful results. Overall increased accessibility to data and self-service portals will allow customers to become more autonomous and have greater levels of satisfaction. Having a robust interface that seamlessly allows customers to access their data and easily track down any questions they might have will also make them less reliant on the call center.

Stage 3 - Program Education/Enrollment: The goal for this stage is to educate customers on the opportunities and benefits associated with participation in utility or third-party services and programs. Similar to Stage 2, a proactive approach supported by technology solutions such as the E-Commerce Portal, described in more detail below, is required. The increased knowledge of opportunities coupled with customer involvement aims to increase customer satisfaction by giving them options to reduce their energy costs.

The diverse customer audience of National Grid, combined with an array of stakeholders representing an assorted set of interests, makes creating dynamic outreach, engagement and education programs essential. This three-stage program will utilize a multi-channel, multimedia campaign that integrates social media to inform and educate energy consumers, ultimately creating a two-way conversation with customers about smart meter technology.

A well-structured plan will increase acceptance, ease implementation, and allow customers to make informed decisions, including participation in innovative pricing programs and other AMI-enabled programs. Ultimately, by readily placing information and data about smart meters into the hands of the customer, National Grid will be able to support customers in realizing the full complement of benefits associated with AMI.

As part of the implementation plan discussed in section 1.3 above, the Company will collaborate with stakeholders to develop a comprehensive customer and market engagement plan that it will file with the Commission during the procurement and design phase in fiscal year 2020. The plan will ensure customers and market participants have the information and access they need to realize the benefits provided by AMI.

3.3 Customers Opt-Out of AMI Meters

Customers will be informed via mail sufficiently in advance of AMI meter installation of their ability and the process to opt-out of the AMI metering program. Processes and resources will be in place to support customers who are considering or have decided to opt-out. Electric customers who opt-out of the program will have an AMI meter installed with the communication capability deactivated. Gas customers who opt-out will not have the gas ERT installed. Customers who opt-out of the program will have their meters read manually on a monthly basis and will be subject to charges per the terms and conditions specified in the Company's opt-out meter reading tariff.

3.4 Cyber Security and Privacy

The Company understands that there are growing cyber security risks in an evolving technology landscape. As part of Phase 1 of the implementation plan, the Company will develop a comprehensive AMI-specific cyber security plan. The Company has developed an overall framework, including a range of cyber security capability investments, to address the new challenges introduced by system modernization, including AMI. At a high level, the AMI-specific plan will ensure that proper end-to-end security controls are incorporated into all aspects of design, implementation, and deployment of AMI technology. These security controls will ensure that all AMI devices, communications infrastructure, and back-office systems, along with user portals and other critical infrastructure, are fully secured and monitored. Moreover, the plan will also ensure that any data transmitted across this network is properly encrypted using nationally recognized standards and protocols.

3.5 Meter Deployment Planning

As described in section 1.3 above the Company is planning a four year meter implementation cycle beginning fiscal year 2021 and ending fiscal year 2024. Actual electric meter and gas ERT deployment may vary from this assumption based on a number of considerations including deployment area customer density, dual fuel customer mix, and benefit realization. The Company plans to develop a more detailed deployment plan following stakeholder engagement during the first year-and-a-half of the program. As part of National Grid's programmatic approach, the exact nature of meter deployment will need to be designed and planned to include timing of meter purchase, staging, resource scheduling, management oversight etc.

3.6 Systems Integration

Systems integration is critical to harnessing the full magnitude of smart meter benefits across National Grid's infrastructure of devices, software, and systems. Only by enabling data exchange between meters and routers, routers and systems, and systems with other systems is it possible to maximize the effectiveness of the overall platform. As such various IT / IS costs associated with systems integration were included in the AMI Business Case model. A well-designed and well-structured approach will include the following:

- Capability analysis and end-to-end definition of functionality at each step;
- Systems architecture to define data interfaces between systems and components;
- Detailed requirements definition for all systems and interfaces;

- Custom configuration and development of system APIs;
- Detailed test case planning and definition; and
- Careful test execution and defect documentation.

A platform such as AMI will have highly complex data exchanges. Throughout the industry, systems integration is supported by an enabling technology known as an Enterprise Service Bus ("ESB"), which helps facilitate the exchange of standardized data elements between all impacted systems.

In addition to a functional platform, other benefits of strong systems integration include:

- Improved system response time and performance;
- Lower labor costs and increased operational efficiency; and
- Compatibility across system devices and software.

3.7 Process Design

Process design is an extremely important component upon which program development and organizational change depends. Many utility employees will be impacted by the deployment of AMI including meter field technicians, meter shop technicians, customer service reps, control center operators, billing analysts, etc. Each role will be changed to some degree to accommodate the incorporation of this new technology. To aid in a smooth transition for both customers and employees, the definition of how people will use the technologies is just as important as defining what the technologies are capable of doing. A strong process includes:

- **Detailed Definition of System Processes and Requirements:** Conduct workshops with subject matter advisors, vendors, end-users, IS representatives, and other key stakeholders to gather, define, and document business processes for the new systems. These sessions, particularly the ones addressing integrations will uncover additional business, functional, non-functional, performance, technical, data, integration, and transitional requirements;
- **Process Design and Organizational Impacts:** Create process flow documents to ensure stakeholder agreement to key sequences, activities, and organizational divisions. Refine processes by documenting requirements, inputs/outputs, contemplated customizations, org/change impacts, KPIs, dependencies, business rules, data needs, data flows, automation touch points, reporting considerations, etc.;
- **Tabletop Processes Simulation Testing:** Leveraging key end-users and a variety of sunny-day and rainy-day scenarios, identify and mitigate pain-points of the newly proposed process; and
- **Cross-Workstream Integration:** The business process team will coordinate with downstream teams to ensure full understanding of documented intent for solution architecting, detailed design, and testing.

3.8 Change Management

Change management is an important suite of tools to deliver stakeholder understanding and behavioral changes to support specific business objectives associated with AMI. This methodology is based on the belief that people's reactions and behaviors at different stages of a change process can be predicted, managed, and measured. The key components of National Grid's smart meter change approach include the following:

- **Readiness Assessment:** Qualitatively identify key stakeholder groups and conduct workshops to assess their expectations, goals, and understanding of the benefits that a program like this would bring. Quantitatively measure readiness to determine if employees: 1) understand the expected changes, 2) have the right skills for the operational phase of the program, and 3) have any barriers to change. Gather information from training metrics, change network surveys, focus groups, and change tracking surveys to develop monthly dashboards which can help define any change management plan modifications;
- **Business Engagement:** Create a tailored plan of engagement for each user group. The change plan will define the sequence, mix, and pace of change activities to help reduce productivity dips and enhance buy-in across these groups;
- **Business Readiness:** Establish an advisory council to create the organizational readiness scorecards and confirm the appropriate metrics for critical functions impacted. Measure progress, identify issues and actions, and update activities in the change plans to incorporate feedback continually from end users;
- **Organizational Design:** Identify new roles, skill sets, and organizations required to operate the new smart meters, infrastructure, and associated systems and correctly size the balance of work between existing back-office functions; and
- **Transition Plan:** Create a knowledge transfer and sustainability plan to identify how various materials (job aids, process flows, etc.) will be transitioned and maintained post deployment.

3.9 Vendor Selection and Management

As discussed in Section 1.3 above, the phased approach toward AMI meter deployment allows time for the Company to issue requests for proposals and engage in competitive and strategic negotiations with vendors to obtain the best prices for its customers. The Company's governance framework will manage and oversee the vendor selection process while considering various factors to include: vendor reputation; current and future delivery costs; prior industry experience; risk mitigation; reporting protocol etc.

3.10 Cost Management and Mitigation

National Grid has the benefit of being able to learn from previous pilots in Worcester, MA and Clifton Park, NY as well as other peer utility experiences. These lessons will provide an opportunity to implement an effective cost management and mitigation strategy. National Grid will ensure that vendor negotiations and contractual terms appropriately limit liability and minimize company exposure.

3.11 Back Office Upgrades and Communication Network Installation

After detailed design and procurement and prior to meter deployment, National Grid will need to ensure the appropriate back office systems have been installed and/or upgraded to be able to handle the incoming interval meter data. Successful transfer of meter data to the AMI Head End and back office systems also requires the implementation and coordination of an effective communication network. These end-to-end solutions will require extensive build and testing. Additionally, the Company will need to develop procedures and training materials while identifying the requisite field and office personnel that need to receive this guidance.

3.12 Measurements of Success

As described in Section 2, and in additional detail in Section 5 below, there are numerous customer and operational benefits enabled by AMI. These benefits will start to be realized as meters are deployed beginning in year three of the AMI program and will continue to increase in future years as the capabilities are leveraged by the Company and 3rd-party market participants to provide improved customer service and value.

During the deployment phase of the AMI program the following three metrics are proposed:

- AMI Program Progress – This measure will track the achievement of key program milestones such as the completion of the back-office systems, customer engagement solutions, and the number of meters installed. These metrics will provide for the appropriate control and oversight of the program.

- Customer Survey Measure - A customer survey will be developed and implemented to measure customer satisfaction with the meter installation process and customer education and awareness as a result of the Company's customer engagement program described above. The survey will be administered on a rolling basis following meter deployment and customer engagement activities.

- Customer Engagement – This measure will track the number of customers who engage in energy management activities through the various customer engagement solutions described later in this document, such as the Energy Management and E-Commerce portals. It will also measure enrollments in various AMI enabled programs including demand response and time variant pricing.

4 AMI COSTS

The AMI program consists of four key elements described below and illustrated in Figure 4-1.

(1) An integrated system of smart electric meters and natural gas ERT's that capture customer usage data and other characteristics at defined intervals;

(2) A Communications network and associated IT infrastructure for acquiring meter and field device data, and enabling Distribution Automation ("DA");

(3) An IT Platform for data collection, monitoring and control of the communication system; an expanded Cyber Security System; a Meter Data Management System ("MDMS") to process meter data; an Analytics platform to convert raw data into intelligent information for use in decision making by Customers and the Company; Customer Engagement solutions; and

(4) Project management and ongoing business operations.

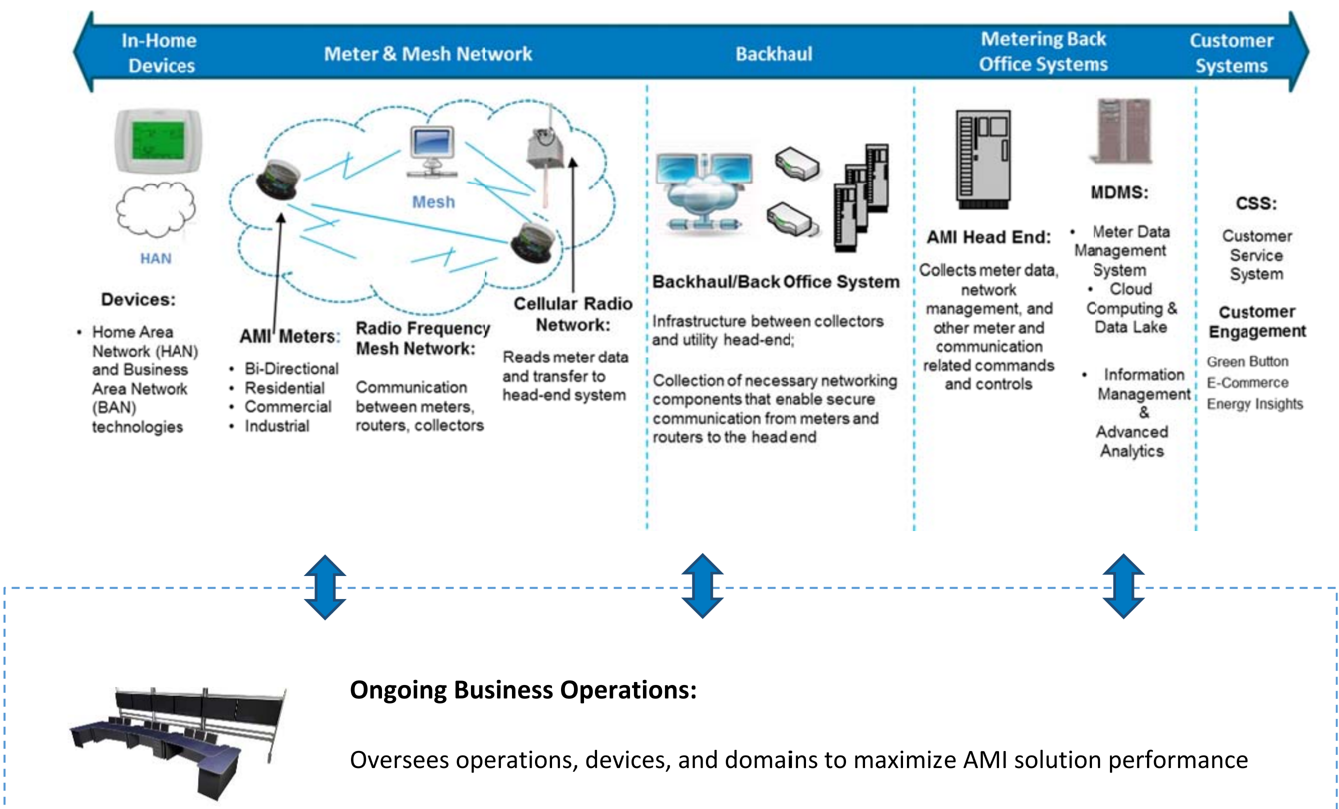

Figure 4-1: AMI Technology Elements

The following descriptions of the end to end metering technologies are meant to provide a broad explanation of the capabilities of individual components presented in this document. Descriptions of components and capabilities defined herein do not constitute a complete list, nor are they linked to any particular vendor or vendors. Rather, it is intended to be directional in nature, establishing the order of magnitude of a comprehensive scope of deployment.

The functions included in the configuration that National Grid is considering include technologies to measure interval consumption, telecommunications to interface with Advanced Metering Mesh and cellular meters; solid-state memory and processing allowing for firmware upgrades, consumption recording, ping support, etc.; sensors for power quality measurement (last gasp notifications, voltage violations, etc.); within the meter’s functionality are autonomous algorithms for abnormal operation (to identify tamper detection, improper measurement, etc.), and the ability to remotely connect and/or disconnect electrical service for customers.

The Company proposes to install approximately 1,692,000 electric AMI meters and approximately 642,000 gas ERTs across its service territory over the four-year meter deployment phase beginning in fiscal year 2021. Actual deployment could vary from the schedule presented in the table based on field conditions and other factors. Meter deployment has been timed to coincide with the planned replacement cycle of electric AMR meters and gas ERTs. Gas meters are on a different replacement cycle than electric meters; however it’s estimated that 10% of the gas meters will require replacement to accommodate new ERT installation.

4.1 <u>AMI Meter Equipment and Installation</u>

An AMI meter is an electronic device used to measure electricity and/or gas consumption at residential, commercial, and industrial locations. This device digitally communicates the interval data using two-way telecommunications infrastructure. These devices can be equipped to leverage either a cellular radio or a mesh network, to interface with a utility’s backhaul and back-office systems.

In all cases, electric meters will have a full kit upgrade including meter, module, and communications device. Gas meter ERTs (a communication device that is capable of securely and efficiently sending information packets a short distance) will be switched out for all meters while 10% of the gas meters are estimated to require replacement to accommodate ERT replacement. Programmatic replacement of gas regulators and meters were not included as part of the scope of this program and will continue to be replaced per current O&M schedules.

4.1.1 AMI Electric Meter Equipment and Installation

The AMI electric meters support the following functionality:

- Flexible Two-Way Communications: Execute all supported meter reading, configuration update and firmware download functionality; customize targeted meter firmware updates; support on-demand readings from the meter.
- Upgradable Firmware: Customize firmware upgrades with the ability to automatically roll-back if activation fails; create multiple firmware images including primary and pending.
- Bi-Directional Metering: Store received and delivered data metrics in the meter; support customers who own renewable energy facilities or participate in vehicle to grid systems with real-time data being sent back to the utility.
- Energy Quantities: Wh Delivered, Received, Net and Uni-Direction; VARh Delivered and Received; VARh Q1-Q4; VAh Delivered, Received and Net.
- Demand Measurements: Max Watts Delivered, Received; Max VA Delivered, Received; Max VAR Delivered, Received; Max VAR Q1, Q2, Q3, Q4; Min Power Factor.
- Automated Meter Reading: Receive and transmit meter billing data including interval data, register reads; transmit recorded events and exceptions with each interval to the head-end software, which interprets them and logs appropriate messages (such as time adjustments).
- Real-Time Meter Event and Alarm Retrieval: Automated alarms received by the head-end system via e-mail to a specific user or group of users.
- Tamper Detection: Detect and report exceptions for events such as magnetic fraud attacks; communicate tamper indications in real time through the system.
- Remote Disconnect/Reconnect: Support integrated disconnect switch; perform remote disconnects/reconnects through the Operations Center.
- Integration & Installation: Fully integrated solution under-the-cover allows for plug and play installation in the field; shipped from the factory as one complete unit, ready for field deployment.
- Meter Security: Platform security with an encrypted file system and secure boot; standard DLMS Security; Application Layer Enhanced Security; Local Access Signed Authorization.
- Adaptive Communications: Support both RF and PLC for “last mile” communication to the meters via the Mesh; support standards based, true mesh communication where each meter is assigned a global routable address; RF links implement standard 4g/e; meters dynamically select the optimal link based on channel conditions and the target QoS; mesh network uses adaptation layers and RPL as a mesh routing protocol; embedded Wi-Fi communications for local access using common security model with network communications.
- Radio Specifications: Radio Output Power; configured at time of manufacture: – 500mW-1W.
- Possesses the ability to communicate with and operate within Home Area Network (HAN) and Business Area Network (BAN) technologies.

4.1.2 AMI Gas ERT Equipment and Installation

The AMI Gas ERT supports the following functionality:

- Continually stores and updates the last 40 days of hourly interval data which can be read via handheld, mobile and fixed network.
- Operates in bubble-up mode and does not require a license from the Federal Communications Commission (FCC).
- Designed for a 20-year battery life regardless of data collection solution to ensure low operating and maintenance costs.
- Module design makes installation fast and easy, especially when gas is flowing through the meter.
- Five-year expected battery life for any meters where customers have opted for advanced data collection patterns (e.g., 15-minute intervals, collected hourly, with approximately 3 firmware upgrades throughout its deployment lifespan).
- Ability to communicate with other gas devices (e.g., methane detectors, remote disconnect valves).
- The compact design and direct engagement with the meter drive assure the unparalleled accuracy that makes gas modules the industry standard.
- The two-way 100G/500G DLN offers improved tilt tamper detection.

4.1.3 AMI Inventory

This cost is for AMI electric meters and Gas ERTs that will be placed in warehouse and local operating area inventories to support ongoing day-to-day operations. An inventory level of 2.5% is assumed and will be phased-in consistent with the AMI meter deployment schedule.

4.1.4 Support Infrastructure

Deployment of AMI meters will require the coordination of a large number of personnel, dispatch activities, new meter staging, new CGR staging, and deposition of removed legacy AMR meters to facilitate disposal. While facility costs are sought to be minimized through equipment just-in time deliveries, some facility costs will be incurred as captured through this line item.

AMI will require additional staff to support field worker management and back office and clerical functions associated with deployed meter characteristics, retired meter characteristics, data cleanup, asset management/customer deployment details. While some existing staff will assist with these efforts, insufficient bandwidth exists for the increased volume of activity during deployment; additional staff is estimated for these functions.

Once AMI meters have been deployed efforts are undertaken from the back office to ping meters and ensure that the deployment was performed correctly. This quality control check confirms that meters are able to communicate with central systems by reporting interval reads, alerts, and other functions as could be expected to be called upon through its useful life. These quality assurance labor cost estimates are captured through this line item.

4.1.5 AMI Meter Equipment and Installation Cost Summary

Table 4-1: AMI Meter Equipment and Installation Costs ($million)

Category	Deployment Period Capital Cost	20-Year NPV (FY19$)
AMI Electric Meter Equipment and Installation	$293.74	$219.17
AMI Gas ERT Equipment and Installation	$73.50	$55.25
AMI Inventory	$6.25	$4.64
Support Infrastructure	$18.37	$13.85
Total	$391.86	$292.91

4.2 Communication Network Equipment and Installation

Technology is evolving every day. National Grid will utilize the best technology available to create a strong, secure mesh network to ensure that the obstacles in Figure 4-2 (high rise buildings; changing RF conditions; underground meter vaults; low-density environments) will not pose significant restrictions in the new network environment.

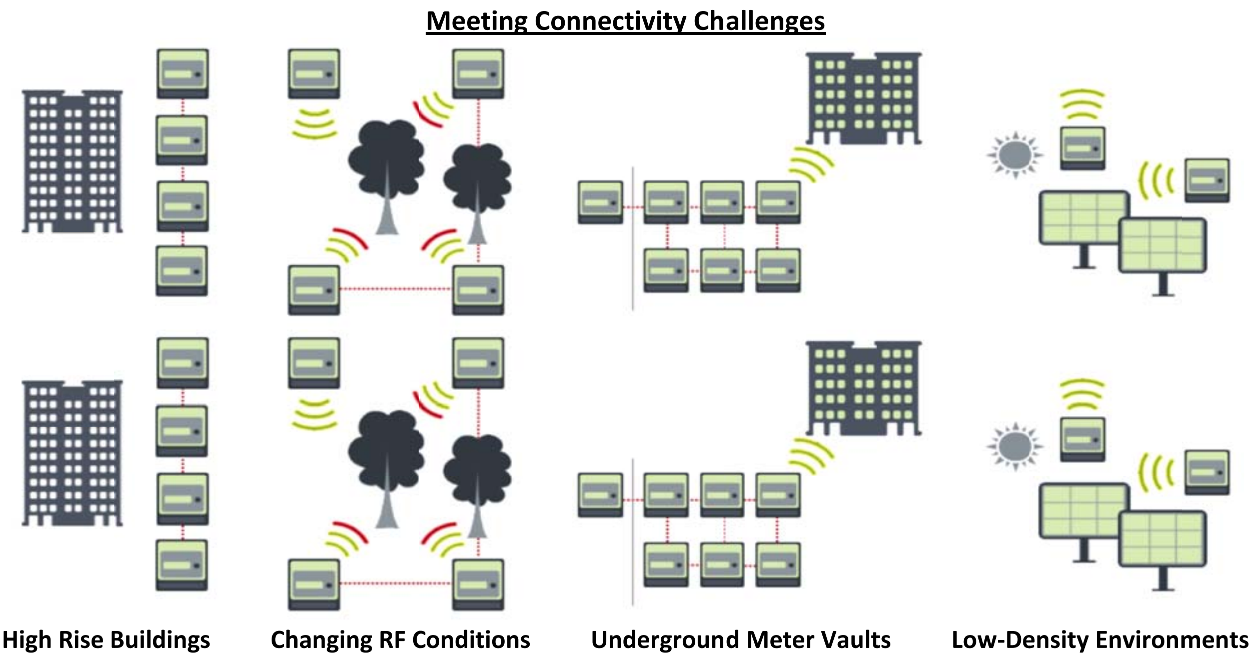

Figure 4-2: AMI Communication Network Illustration

4.2.1 Network Equipment and Installation

Embedded within each meter is a communications module that enables the meter to communicate with back office systems. These modules can either be outfitted with mesh or cellular radios. Circumstances like relatively populated densities, topography and seasonal conditions will influence the type of communication utilized.

The principal focus of AMI network design is to support accurate and timely meter communications and data collection. While various grid automation functions, such as Volt-VAR optimization may utilize the AMI data, communication to distribution automation devices will utilize a separate communication network from the AMI network.

The radio frequency mesh network is created by including a low-power, short-range radio in each meter. Each meter is able to transmit its own load profile as well as a finite collection of data from downstream meters. All meters with this technology dynamically communicate with each other to identify optimal communication pathways back to centralized data collection points. In doing so, these networks of devices can self-identify the most efficient paths on an ongoing basis and dynamically reconfigure to maintain optimal routing in varying operational situations.

For most urban/suburban areas where a sufficient population density exists, National Grid will utilize this radio frequency mesh network to facilitate meter communication with the backhaul system. The meters will utilize a relay/router system to transmit the meter data back to the back-office systems, as well as transmit data from the back office to the meters in the field in a bi-direction manner.

When possible, the electric meter will serve as the communications platform for the gas meter. The platform will enable communication between the gas meters and the back-office systems while efficiently optimizing impacts to the gas meter's battery life. Further analysis and technological advances will dictate the environment for gas only customers as it pertains to a mesh communications network.

In certain circumstances, a cellular radio will be used instead of the mesh network. The conditions for cellular radio use include lack of population density to support a mesh network, topology, and gas only customers. For deployment, it is assumed that up to 5% of devices will be direct cellular.

Collectors and routers are the equipment that facilitates transmission of data from the mesh network linked AMI meters to the back-office systems. It should be noted that there are innumerable infrastructure configurations possible for the communications network. The transmission of data may utilize multiple types of devices from a variety of vendors, which pull in and transmit data to the next node in the communications pathway on the way to the back-office system.

The collectors and routers have a number of characteristics that enable communications efficiency and effectiveness. They are:

- The network is able to rearrange itself dynamically to maintain the most efficient communications pathways across seasons, varying weather conditions and vegetation cycles;
- In the event of a power outage, the FAN will stay up long enough to transmit a power-off notification to alert the outage management system ("OMS") of the problem;
- Multiple types of devices that collect and transmit digital interval data: Collectors: larger bandwidth devices for maximum throughput of data to manage data collections; Relays: smaller device that is used to extend the range of communications for Spur; Meters: small short range device used to aggregate a small number of meters; and
- Sub-System Support - Devices / Antennas / Sensors.

It should be noted that overall network design and configurations implemented in each device impacts transmission speed.

As part of the AMI Business Case, various emerging capabilities were reviewed in the smart meter landscape. One feature on the horizon is the near real-time data collection from AMI meters that allows bill quality data to be accessible for customers. It should be noted that real-time data collection is conceptual at this time. While smart metering vendors have given estimates of the achievability of "real-time" data collection, the Company is not aware of any such deployments.

The general industry standard for AMI implementations in the United States has been to make bill-quality interval data available within 24 hours of collection. Under the Company's program electric customers will have access to their raw, not validated, edited and estimated ("VEE"), usage data within four hours after an interval. Gas customers will have access to this raw usage information within eight hours due to battery limitations. In both cases, customers will have bill quality data within approximately 24 hours of the end of a given interval. The Company expects to engage stakeholders further with respect to their real-time information access needs.

The streaming of low-latency (i.e., "real-time") and high granularity usage data already has several applications in the marketplace. Currently there are several possible methods of streaming real-time data to customers and DER providers. Even though current technologies exist for streaming applications, future technologies and industry standards will dictate National Grid's application.

4.2.2 Communication Network Installation Management

During the network installation and meter deployment phase of the program internal Company department resources will be paired with meter vendor resources under the direction of the AMI program management team to manage the communications infrastructure, meter deployments, and coordinate the initial stabilizations as appropriate. This team will also be responsible for troubleshooting any meter related issues that occur during this phase. Once the meter deployment phase is complete, these responsibilities will be permanently assigned to the appropriate departments.

4.2.3 Backhaul

The backhaul network is a wide area network ("WAN") that is the high-speed, high-bandwidth communications structure between the collectors and the AMI Head-End. The network can either be public or private depending on several factors, including cost (both upfront and reoccurring), security, meter density in the area and distance from the existing fiber network.

Regarding private communication, National Grid has a SONET fiber communications system that ties a number of larger transmission substations and other corporate facilities together. In some instances, distribution level substations also leverage this network to send operational data back to our corporate facilities. In addition to fiber optic systems, the Company operates a large number of licensed and unlicensed microwave point-to-point links that provide backhaul connectivity for multiple operational and corporate systems.

AMI collectors will backhaul their data utilizing 4G cellular networks or company private networks when located at substations or other company facilities with private network connectivity.

4.2.4 Communication Network Equipment and Installation Cost Summary

Table 4-2: Communication Network Equipment and Installation Costs ($million)

Category	Deployment Period Capital Cost	20-Year NPV (FY19$)
Network Equipment and Installation	$6.06	$7.95
Communication Network Installation Management	$9.49	$8.19
Backhaul	-	$2.78
Total	$15.55	$18.92

4.3 IT Platform and Ongoing IT Operations

Five IT platform elements are included as part of the AMI program; AMI Head-end and Meter Data Management Systems, enhancements to the Customer Service System, Customer Engagement Products and Services, IS Infrastructure, and Cyber Security. Each of these elements is described below.

4.3.1 AMI Head-end and Meter Data Management Systems

The AMI Head-end is the communication, command, and control system that integrates the communications infrastructure in the field and the back office systems. The AMI Head-End communicates with AMI meters to collect meter data from reads and events. It also can ping individual meters as necessary and push firmware updates across the network. For electrical systems, it can remotely initiate the connection and disconnection of meters. This system serves as the main point of data collection and disbursement for data being transmitted in either direction, to/from meters.

An effective AMI platform requires an MDMS. The MDMS provides AMI meter data storage and archival capabilities for interval meter read information. The MDMS also processes the incoming meter data by VEE the interval data that is received by the program. Once the raw data has been processed, it can be utilized by back-office systems like billing, customer service, and data analytics. In addition, the data can be uploaded to the web portal for customer use and/or authorized market participants.

An important function of the MDMS is the VEE process. This is a method where the MDMS reviews all un-validated data from the AMI meters in an effort to identify anomalies. This is data that fails validation because it falls outside an expected range and is flagged for review by metering agents. In addition to failed validations, incomplete or missing interval reads are also highlighted. These flagged data intervals are estimated as the final step of the process and can be updated once additional data has been received or the original data has been validated.

Cost estimates in this area assume the Company contracts with an outside service vendor to host these systems. The arrangement is referred to as Software as a Service ("SaaS").

4.3.2 Customer Service System

The customer service system (CSS) is a set of applications utilized to manage customer-facing activities. The set of programs pulls meter data to administer orders, billing and payment processing, collections, rebates and discounts for EE and DR, and other pricing program rates and usage. As part of the AMI deployment, the CSS will be modified and configured to accept data formatted for more frequent intervals. The CSS will also be configured with parameters to interpret this interval data so that usage can be priced by programs such as time-of-use ("TOU") and CPP. Having such a prominent role in customer interaction with National Grid, an effective CSS with appropriate capabilities is critical to maintaining customer satisfaction. Moreover, as DER penetration increases throughout Upstate New York, the CSS must be adaptable to changing with the dynamic energy environment.

The CSS also includes capabilities intended to foster a relationship with customers and assist in customer retention through personalized service. The system pulls from various back-office IT/IS sources to create personal profiles on customers to facilitate customer engagement. For instance, CSS can be linked with interactive voice response ("IVR") to send an automated notification to customers when the system receives a power-off notification from AMI meters. Additionally, the CSS will present customer history and real-time meter status to the call center operators when customers call in, giving National Grid employee's greater insights to help customers. Service representatives will also have a new suite of tools at their fingertips to perform diagnostic services instantly on or ping meters when issues arise. They will also have the ability to restore power that has been disconnected whether it is for non-payment or seasonal usage.

4.3.3 Customer Engagement Products and Services

In order for the benefits of smart meter technology to be fully realized by the customer, the Company recognizes the importance of pairing this technology with proactive customer and market engagement initiatives. As part of the AMI deployment, National Grid will develop and implement an Energy Management Portal, Green Button Connect My Data, E-Commerce Portal, and a Demand Response Management System ("DRMS"). The cost of these solutions is included in the AMI benefit cost analysis.

- The Energy Management Portal will act as a hub for residential, commercial, and industrial customers to view their energy usage, including AMI meter interval data. This platform will allow customers to view billing quality data within 24 hours. Access to this data will enable customers to make better-informed decisions about how they use energy. The portal will power customer choice, giving customers the option to enroll in programs that can leverage the more granular data provided by AMI. These include EE, DR, and other pricing programs. Customers can also access educational and safety information, material on energy efficient consumer products, and analysis on home energy usage. The platform will also be integrated with smartphone applications that allow customers to access their data on the go, in addition to being able to create customizable alerts notifying them of grid conditions (including outages, reductions or curtailments), unusual usage, and bill pay.

- Many utilities, including National Grid, have implemented Green Button Download My Data. This system gives every utility customer the ability to download their personal energy consumption data directly to their computer in a secure manner. Additionally, if customers are interested, they can upload their data to a third party application.

  Green Button Connect My Data takes this process further by streamlining it to allow utility customers to automate the process. With Green Button Connect My Data customers can securely authorize both National Grid and designated third parties to send and receive data on the customer's behalf as may be seen in Figure 4-3. Upon authorization, energy usage data can be transferred as required.

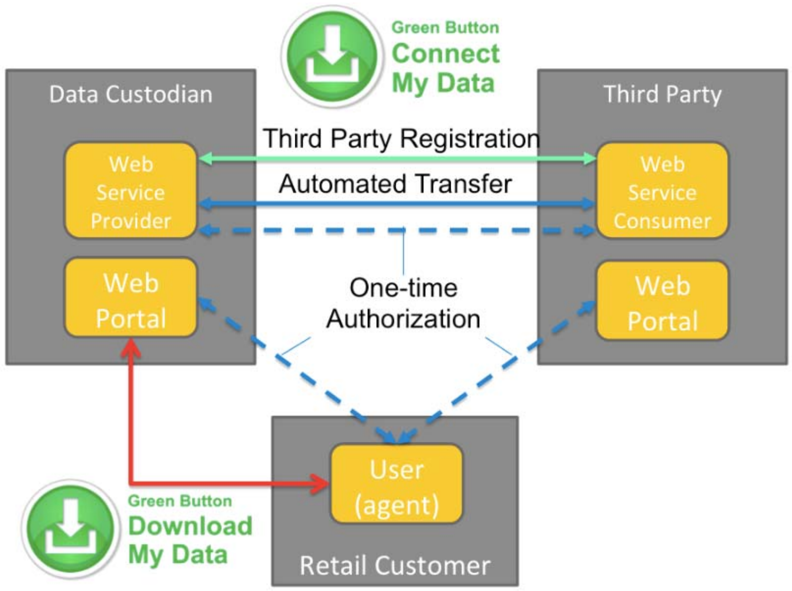

Figure 4-3: Standard communications protocol for Green Button Connect My Data

- The E-Commerce Platform is a proposed online marketplace where customers can shop for energy efficiency and demand response products such as LED lighting, faucet aerators, and smart Wi-Fi thermostats. Customers will be able to view product features and reviews, compare prices, and be able to redeem rebates on qualifying products for which they are eligible. Purchases are shipped directly to the customer's home or business similar to other e-commerce websites.

- A DRMS focused specifically on commercial and industrial customers is needed to automate demand response programs. The proposed DRMS will allow for more effective program delivery by providing commercial and industrial customers with a simple, easy to use platform to register their assets and receive reports on their performance.

4.3.4 IS Infrastructure

The following IS Infrastructure capabilities are required to support the AMI systems:

- Telecommunications - Enhancements are required to expand existing backhaul capabilities and bandwidth to support data transfer.
- Enterprise Service Bus (ESB) - To implement several of the AMI and ADMS use cases, systems in the new distribution ESB will need to communicate with legacy systems that currently use a corporate ESB.
- Information Management & Advanced Analytics - Costs in this category allow data ingestion, data quality and analytic capabilities to be configured and deployed. The big data analytics capabilities will allow for the analysis of the data gathered from existing and third-party data sources to provide valuable output reflecting current state as well as predictive and prescriptive outcomes.

- Cloud Computing & Data Lake - Rather than hosting these data management capabilities on servers within National Grid data centers, greater efficiencies, redundancies, and security regimes can be cost effectively procured by outsourcing this function. This cost element captures the costs associated with setting up a cloud data lake environment.

4.3.5 Cyber Security

The Company understands that in an evolving technology landscape, there are growing cyber security risks. To best secure AMI, National Grid is preparing a comprehensive cyber security plan to ensure protection for both customers and the company. At a high level, this plan will ensure that proper end-to-end security controls are incorporated into all aspects of design, implementation, and deployment of AMI meter technology. These security controls will ensure that all AMI meter devices, communications infrastructure, and back office systems supporting them, along with user portals and other critical infrastructure are fully secured and monitored. Moreover, the plan will also ensure that any data transmitted across this network is properly encrypted using nationally recognized standards and protocols.

The Company will leverage industry-leading best practices to meet the goals of a robust cyber security program. These practices include robust training, change control, configuration management security, access monitoring, incident management, end-to-end encryption, network segmentation, and firewalls, as well as other security controls. The cyber security measures outlined will enable National Grid to maintain confidentiality and integrity to the best of its ability in both the short and long term future of AMI.

The business case reviewed the high level cyber security service domains based on the cybersecurity strategy, services and controls that are defined by National Grid in its Distributed System Implementation Plan ("DSIP") filing. The scope of the DSIP covers Advanced Meter Infrastructure (AMI), Grid Modernization (including systems and components to enable VVO, FLISR, etc.), and the overall Distributed System Platform (DSP).

All systems, components, and integrations from the AMI Business Case were considered as part of this review in consideration of the following service domains:

- Network Security Services
- Data Security Services
- Identity & Access Management Services
- Threat and Vulnerability Management Services
- Security Operations Center Services
- Host and Endpoint Security Services
- Security Policy Management Services
- Cryptography Services
- Change & Configuration Management Services
- Security Awareness & Training Services
- Application Security Services

- Third Party Assurance Services
- Remote Access Services
- Privacy Services

4.3.6 IT Platform and Ongoing IT Operations Cost Summary

Table 4-3: IT Platform and Ongoing IT Operations Costs ($million)

Category	Deployment Period Capital Cost	20-Year NPV (FY19$)
AMI Head-end and Meter Data Management Systems*		
Customer Service System		
Customer Engagement Products and Services		
IS Infrastructure		
Cyber Security		
Total	$166.11	$226.61

* Assumes SaaS payments are capitalized and are discounted to 2019 dollars

4.4 Project Management and Ongoing Business Operations

4.4.1 Project Management

AMI Project Management will provide the necessary framework for the successful integration of interdependent technology components and processes through the proposed a five-and-a-half year AMI program. The project management team will consist of internal project management leadership, internal business support and external support.

4.4.2 Equipment and Installation Refresh Cost

This area includes the following cost elements:

- AMI meter replacement cost recognizes that over time meters will fail. While a warranty is provided on meters for a one-year period, after this period expires, it will be National Grid’s responsibility to procure replacements. This cost is applicable to both electric and gas metering capabilities.

- A subset of electric meters will be located in rural areas with insufficient density to form a stable and consistent mesh. For these electric metering locations, an electric meter with a cellular radio will be installed instead of one with a mesh radio. The electric meters that use a cellular radio for communication have a corresponding ongoing service fee with public cellular providers.

- AMI meters communicate with each other through mesh technologies for local communications but rely on more robust communications equipment for backhaul to back office systems. The core piece of equipment to perform this function is a

Connected Grid Router (CGR) which can aggregate data from local metering mesh clusters and convey pertinent data through publicly available cellular wireless. Over time, it is expected that these devices will fail and require replacement. This cost element addresses the costs of the replacement equipment and the installation cost associated with replacing failed equipment throughout the duration of the program.

- For CGRs used to support electric AMI meters / gas ERTs, each device has a corresponding, annual service fee allowing it to communicate with the public cellular backhaul. These cost elements are annual cost for operations.

4.4.3 Ongoing Business Management

AMI deployment will require additional operational support to monitor and manage system performance and oversee numerous AMI processes such as; the VEE process; field area network performance; investigation and remediation of meter and communications infrastructure problems; and firmware deployments. The Company's pilot experience is used to estimate these costs.

4.4.4 Customer Engagement Cost

AMI metering introduces many points of change for customers to understand. Considering the full scope of change, these topics include the following:

- Process and timing for physical meter exchange
- Safety of new meter technologies
- New information and resources available for customer programs

Customer engagement will be varied and dynamic including physical mailers, town hall sessions, dedicated portion of web portal, knowledgeable customer service reps, etc. Given these approaches, the large volume of customers requiring engagement, and the duration of deployment, a detailed plan must be compiled to guide the activities to be undertaken. This design effort will cover schedule definition, stakeholder group identification, forums, channels, topics, content development, etc.

Part of the customer engagement approach is the use of mass media to engage and inform customers of the changes associated with the AMI metering program. These media approaches require radio and television expenditures. Given the size of National Grid's New York territory, mass media buys will be performed in numerous metropolitan areas. This line item captures the cost of these media buys in various markets.

Another means of customer engagement is targeted messaging. This category assumes a combination of letters, postcards, and robo calls to provide information to each customer. These messages will be adjusted to reflect different impacts for electric only, gas only, and dual fuel customers. This cost category aims to capture the costs of production and delivery of these messages.

4.4.5 Project Management and Ongoing Business Operations Cost Summary

Table 4-4: Project Management and Ongoing Business Operations Costs ($million)

Category	Deployment Period Capital Cost	20-Year NPV (FY19$)
Project Management	$4.15	$11.47
Equipment and Installation Refresh Cost	$0.54	$8.28
Ongoing Business Management	-	$24.19
Customer Engagement Cost	-	$25.60
Total	$4.69	$69.54

5 AMI BENEFITS

5.1 Avoided O&M Costs

5.1.1 AMR Meter Reading

National Grid currently has a fleet of AMR meters covering its electric and gas service territory. These AMR meters have monthly reads that are acquired through radio frequency technology. These collections are done by a fleet of service vans which meter readers drive along routes to allow communication with each meter. Starting in fiscal year 2021, National Grid will replace its current AMR meters with AMI meters which will avoid the need for AMR meter readers, associated vehicles and AMR meter reading annual software costs.

5.1.2 Meter Investigation

Smart meters will provide auto and on-demand meter reads and diagnostics to alert and inform the Company about anomalous situations that in-turn allows for the reduction of visits to the meter for manual meter investigations. This will reduce labor and vehicle costs. The type of manual meter investigations that can be avoided in full or part include: Check Electric Meter Multiplier Investigations, Irregular Electric Meter Investigations, Electric Meter Number Verification Investigations, Use on Inactive Electric Meter Investigations, Meter Reads, and High Bill Meter Reads.

5.1.3 Remote Connect and Disconnect

Advanced Metering provides the ability to connect and disconnect electric service remotely and in near real-time. This capability can be used in various service situations to avoid initial and in some cases repeat visits to the meter for manual meter connects and disconnects. The estimated savings assumes the Company would need to continue manual field connects and disconnects for dual fuel customers. With respect to collections related disconnects, the company will comply with all Home Energy Fair Practices Act (HEFPA) requirements including visits to the customer premise. Avoided meter visits will reduce labor and vehicle costs.

5.1.4 Reduction in Damage Claims

In the course of business, despite efforts for mindfulness and safety consciousness, accidents occasionally occur. In certain circumstances arising from driving to/from service orders, routine meter reading routes, or other day to day activities, damage to third party property can occur. As discussed during some of the previous AMI benefits, the advanced metering technologies will allow for remote interaction that will keep metering service reps off of the road and away from customers' premises. The reduction of opportunities for accidents and damage to occur will reduce damage claims.

5.1.5 Avoided O&M Costs Summary

Table 5-1: Avoided O&M Costs ($million)

Avoided O&M Costs	20-Year NPV (FY19$)
AMR Meter Reading	$45.78
Meter Investigation	$5.47
Remote Connect and Disconnect	$57.08
Reduction in Damage Claims	$9.46
Total	$117.79

5.2 Avoided AMR Costs

5.2.1 Capital

The AMI program will avoid the need and associated capital costs of the life-cycle replacement program for the existing electric AMR meters and gas ERTs. The business case assumes the programs are aligned in terms of the timing of electric meter and gas ERT replacement. The AMR life-cycle replacement program includes many of the same capital activities as the AMI program such as electric meter and gas ERT installation, communication equipment upgrades, and project management. The avoided cost of these similar activities are estimated as part of, and consistent with, the AMI model.

5.2.2 Operations & Maintenance

The AMI program will avoid the need and associated O&M costs of the life-cycle replacement program for the existing electric AMR meters and gas ERTs. The business case assumes the programs are aligned in terms of the timing of electric meter and gas ERT replacement. The AMR life-cycle replacement program includes many of the same O&M activities as the AMI program such as call center calls, customer communications, and project management. The avoided cost of these similar activities are estimated as part of, and consistent with, the AMI model.

5.2.3 *Avoided AMR Costs Summary*

Table 5-2: Avoided AMR Costs ($million)

Avoided AMR Costs	20-Year NPV (FY19$)
Capital	$254.35
Operations & Maintenance	$21.24
Total	$275.60

5.3 Customer Benefits

5.3.1 *Volt-VAR Optimization ("VVO")*

The more granular and frequent data from AMI meters enhances the effectiveness of this program. In particular, a subset of AMI meters can act as end of line sensors that provide real-time information to centralized control systems to adjust grid operational characteristics. More granular metering information can also define more precise load models of individual circuits with adjustments for time of day and year or temperature correlation. For the purposes of this business case, the Company recognizes VVO benefits that would be considered incremental to those achieved by Grid Modernization.

5.3.2 *Energy Insights/High Usage Alerts*

Through the deployment of AMI smart meters and associated back-office infrastructure, the Company will have access to customer usage data in near real-time, with granularity at sub-hour reading intervals. National Grid will be building an Energy Management Portal that will act as a hub for residential, commercial, and industrial customers to view their energy usage, including the smart meter interval data. This platform will allow customers to view billing quality data within 24 hours. In addition to allowing customers to view their energy consumption in near real-time, the Energy Management Portal will allow customers to compare their usage and costs against certain variables such as weather, historic consumption at the same time and dates, and neighbors' usage to understand factors that may be driving their energy use.

Armed with this information, customers can take action using the functionality that the Energy Management Portal provides. This could include shopping for energy saving products and services through the Company's proposed E-Commerce Platform and Residential Solar Marketplace that will be linked to the Energy Management Portal, or enrolling in energy efficiency, demand response, and other pricing programs. In addition, customers can access the Energy Management Portal for energy savings programs and personalized energy tips and strategies to reduce their energy usage and save money. The Energy Management Portal can also be customized with alerts, notifying customers of high use or events on the electric system such as an outage.

As marketed by OPower,[3] their energy efficiency products/portals can achieve energy savings of up to 3% by empowering customers with personalized insights. For the purposes of this business case, the Company conservatively recognized a net .5% savings of residential gas and electric sales through the combination of anticipated participation and average energy savings.

5.3.3 Time Varying Pricing ("TVP")

5.3.3.1 Introduction

AMI deployment will allow National Grid the opportunity to provide more granular, time-variant price signals to customers. TVP options for customers provide them with opportunities to reduce energy consumption and/or shift usage from high cost periods to lower cost periods, resulting in savings on the system and advancing the goals and objectives of REV.

The following section provides an overview of an example design and net benefits analysis of TVP with two components: time-of-use ("TOU") pricing, where different energy prices are defined and set for specific intervals of the day (e.g., the afternoon, evening, night, etc.); and Critical Peak Pricing ("CPP"), which adjusts rates to a higher level during certain operational conditions. The next section will discuss the Company's defined CPP example that would apply during a limited number of hours defined on a day-ahead basis based on expected grid conditions. The Company has evaluated an opt-out scenario where, by default, a large percentage of customers will be enrolled in these pricing programs, as well as an opt-in scenario, in which customers must choose to enroll on the rate. Through educational initiatives and pricing signals designed to encourage efficient consumption behavior, over time customers will proactively shift portions of their energy consumption to times of day where energy rates are lower, thereby resulting in reductions in their electric bills. In addition to incentivizing customers' savings, consumers shifting their energy usage will flatten the overall load curve. This shift, combined with other programs such as VVO and energy efficiency, will lower energy peaks, thus reducing expenditures on generation capacity.

The following description of the approach and TVP rate design is an example of how one such methodology could be used with AMI to provide customers with the tools necessary to reduce supply costs on their monthly electric bills. The scenarios described herein are intended to be illustrative – actual rate designs proposed by the Company during AMI deployment may differ from what is described below.

5.3.3.2 Overview of Approach

The benefits from the Company's illustrative TVP program will result from savings in generation capacity costs and savings in energy costs. A significant cost for utilities is the Annual Generation Capacity Cost (AGCC). This cost is a payment to generators (particularly peaking plants) to ensure that sufficient generation capacity is available to support load throughout the

[3] OPower.com, Energy Efficiency Products, Copyright ©2016.

year. The AGCC is calculated based on a prior year's peak generation MW with an added Reserve Margin to mitigate unexpected demand spikes. By definition, a peak only occurs once throughout the year with the majority of the load being significantly below the procured capacity. This presents an opportunity to more effectively manage the peak load and resulting AGCC. Energy cost savings result from a reduction of peak energy consumption and a resulting reduction in the hourly marginal generation cost at the NYISO.

The level of benefits achieved will be directly related to the 1) number of enrolled customers and 2) the level of customer response to the new price signals and the resulting peak and energy savings. National Grid recognizes that customers will require education, training and access to tools that will enable them to become active participants in TVP programs. For example, customers will need to fully understand the cost implications of consuming electricity during hot summer days, as compared to a springtime morning, as well as how specific technology and program offerings can help them manage their energy costs. With this in mind, the Company evaluated both "High" and "Low" scenarios that vary assumptions about peak reductions and reduction in on-peak energy use.

Creating an optimal TVP program could be achieved over years of phase-ins or introductions of new rate designs, software tools, data availability and customer education. This means an optimal design could evolve over time, while the conceptual approach provided herein is meant to be illustrative of how such programs could be implemented. The TVP program considered in this analysis will consist of two supply pricing components.

> **Time of Use ("TOU")** – supply prices will vary by specific times of day, every month, with peak (higher price) and off-peak (lower price) periods defined. In response to TOU rates, customers save by reducing consumption during higher cost peak periods and/or shifting use from peak to off-peak periods.
>
> **Critical Peak Pricing ("CPP")** – supply prices will increase further by time of day on a limited number of specific days (typically during high demands on the electrical system, where customers are notified in advance) designated as CPP events. CPP is designed to recover most of the costs for generation capacity in the hours that have the greatest need for peak capacity. When customers avoid consumption during the highest peak loads of the year, future generation capacity costs established and required by the NYISO on all utilities are avoided and the result is savings to capacity costs that are included in supply rates for customers. CPP events would be limited to a specific number of days and during specific hours of the day, which gives customers a greater level of flexibility.

5.3.3.3 Rate Design

The proposed TOU component of the example rate consists of two time periods with different prices. The first time period is an off-peak period which has the lowest prices. This period includes all weekends, holidays and the weekday hours beginning at 11:00:01 P.M. and ending at 7:00 A.M. The second period is for non-holiday weekdays from the hour beginning at 7:00:01 A.M. and ending at 11:00 P.M. These two time periods are consistent with the periods in the Company's current VTOU rate offering and reflect that, on average, electricity prices are higher during the weekday. The CPP component of the rate adds an additional time period that will overlap with the TOU periods. Unlike TOU time periods, specified CPP time periods are not predefined, except for the fact that these hours occur on weekdays. Instead, CPP time periods are defined in reaction to actual load conditions on the electrical system. This is typically accomplished in a day-ahead method. High demands on the electrical system typically occur during the hottest days of the summer, which can be predicted with some accuracy a day in advance, since the predominant factor of high loads is weather. If NYISO forecasts very high loads or peak conditions for the next day, National Grid will notify customers that electricity prices for a select number of hours the next day will be at the considerably higher levels.

Designing a CPP rate requires determining the number of potential days and hours that a CPP event can be called. This determination requires careful analysis of historic hourly system loads from NYISO. For the first step, National Grid employed a statistical technique called Cluster Analysis to place days into groups with similar peak loads. Cluster Analysis puts load levels into groups in a way that decreases the differences between loads within a group while increasing the difference between other groups. The analysis used the peak load in each day for 2015 and 2016. The analysis resulted in 31 workdays in 2015 and 43 workdays in 2016 falling into the cluster with the highest peaks, as shown in Table 5-3 below.

Given that the number of days that emerged from the cluster analysis was higher than the number of CPP events the Company could reasonably call, the Company further reviewed the load curves on the days identified by this analysis to define the number of days and hours to apply the CPP. A threshold of 27,500 MW was defined to balance the need to limit the number of called events with the need to have a threshold that would encompass the full peak period on the highest-peak days. The Company then counted the number of hours in these critical peak days that were above the 27,500 MW threshold. The number of days and hours implied by potential thresholds based on 2015 and 2016 load data is shown in Table 5-3. National Grid selected the hours above a load level that does not occur on any other day of the year except for the days in this grouping. This resulted in a total of 139 workday hours for 2015 and 183 workday hours for 2016. The Company proposes to use the average of these two years, or 161 workday hours, as the basis for design of the illustrative CPP.

Table 5-3: Summary of potential thresholds and implied potential CPP days and hours

2015				
Potential threshold	Days with peaks above threshold	Hours on those days	Workdays with peaks above threshold	Hours on those workdays
26000	31	257	28	245
26500	27	213	26	206
27000	24	179	23	174
27500	23	142	22	139
28000	18	105	18	105

2015				
2016				
Potential threshold	Days with peaks above threshold	Hours on those days	Workdays with peaks above threshold	Hours on those workdays
26000	43	371	38	321
26500	37	303	32	262
27000	32	257	29	224
27500	31	209	28	183
28000	25	163	22	143

Calculation of Illustrative Prices

National Grid designed an illustrative CPP rate using the calculations shown in Table 5-4. This calculation adjusts for NYISO Reserve Margin requirements, Demand Curve and thermal losses. The cost per kW of generation capacity is calculated on a cost per kWh basis for the critical peak period. The annual cost for 1 kW is calculated and divided by the number of hours in the critical peak period. Table 5-4 provides the calculation of the per kWh charge of $0.099679 for capacity costs. Under the example, the Company can call this price for 161 workday hours on 20 days in the year. As discussed above, in the example National Grid proposes to recover 100% of the capacity cost in the critical peak period, which will require the Company to forecast capacity costs for these periods. Actual capacity costs and timing differences would be reconciled in future supply costs.

CPP Rate = Avoided Generation Capacity Cost x # CPP days × Length CPP Period × % System Risk Captured

Table 5-4: Example of CPP Adder Rate Design

Niagara Mohawk Power Corporation Calculation of Time Variant Pricing – CPP Rate	
Data Description:	
(1) Peak Load (kW)	1 kW
(2) Thermal Losses (Secondary)	6.40%
(3) NYISO Reserve Requirement %	7.0%
(4) Demand Curve Requirement %	10.0%
(5) Clearing Price ($/kW-month)	$9.61 /kW-month for Year 2020
(6) Capacity Payment (Line 1 x (1 + Line 2) x (1 + Line 3) x (1 + Line 4) x Line 5)	$12.04
(7) # Months to allocate Capacity $ to CPP Event hours	12
(8) Total Capacity Payment (Line 6 x Line 7)	$144.44
(9) Desired # of Hours in all Critical Peak Events	161
(10) Probability Coincidence Peak Factor	90%
(11) per kWh Capacity Payment (Line 8 ÷ Line 9 ÷ Line 10)	$0.99679 /kWh CPP Rate
(12) Maximum # of Hours in CPP Window	8
(13) Maximum # of CPP Events called per Year (Line 9 ÷ Line 12)	20

As shown in Table 5-5, illustrative retail TOU energy billing rates were created by using forecast OnPeak and OffPeak market prices for the peak and Offpeak periods specified above. For this illustrative rate design, an assumption on load weightings was used, based upon the Company's current residential load shapes. OnPeak and OffPeak load weightings are necessary to convert an hourly market price per MWh to a retail load-weighted rate. Additionally, ancillary services are added and multiplied by thermal losses to arrive at billable retail rates for the OnPeak and OffPeak periods. The supply prices used in this illustrative rate design are based upon current forecast for 2019.

A revenue-neutral adjustment could be made to the retail rates to develop OnPeak and OffPeak rates that meet acceptable design objectives around the peak/off peak price ratio. These design objectives can provide enhanced economic incentives for customers to shift energy usage from OnPeak to OffPeak compared to the pure market price signals.

Table 5-5: Example of TOU Rate Design

Niagara Mohawk Power Corporation Calculation of Time Variant Pricing – TOU Rates		
(1)	Forecast OnPeak Energy (LBMP Year 2020)	$0.0506 /kWh
(2)	Forecast OffPeak Energy (LBMP Year 2020)	$0.0337 /kWh
(3)	Ancillary Services	$0.0025 /kWh
(4)	OnPeak Load – Price Weighting	105.7%
(5)	OffPeak Load – Price Weighting	94.8%
	Forecast Rates	Rates
(6)	OnPeak Energy Rates	$0.05972 /kWh
(7)	OffPeak Energy Rates	$0.03654 /kWh
(8)	OnPeak Adjustment Factor	102.00%
(9)	OffPeak Adjustment Factor	96.70%
	Adjusted Forecast Rates	Rates
(10)	OnPeak Energy Rates	$0.06092 /kWh
(11)	OffPeak Energy Rates	$0.03534 /kWh
(Energy Rates are (LBMP + Ancillary Rates) x Thermal Losses)		
(12)	**TOU Design Objective #1**	
	OnPeak Rates should be > 1.67 x OffPeak Rates	1.7 Good
	(NYSEG uses 1.50 and ConEd uses 1.67)	
(13)	**CPP Design Objective #2**	
	CPP Rate = 15 x the OffPeak Energy price	28.2 Good

In this illustrative example shown in Tables 5-4 and 5-5, two design objectives were used to develop retail rates (shown in Table 5-5). These design parameters are consistent with other NYS utilities. The first design parameter is the “peak-to-off-peak price ratio” for the TOU period rates. The ratio of average peak to off-peak prices should yield a price ratio of at least 1.5.

On CPP days, the second design objective is for the CPP peak to off-peak price ratio to yield an approximate ratio of 15 to 1. This rate gives residential consumers a strong incentive to reduce peak period energy use on CPP days and a modest incentive to reduce it on non CPP weekdays. Other design parameters necessary in a TVP program are the CPP maximum number of events and maximum number of hours to be called in a summer, and the maximum number of hours in a window. These parameters are guidelines that can be adjusted from year to year, but are necessary to give customers the proper information to make economic decisions on their energy consumption and usage patterns.

5.3.3.4 Calculation of Potential Savings

Energy and capacity savings were calculated for four scenarios: 1) Opt-in TVP with low customer responsiveness; 2) Opt-in TVP with high customer responsiveness; 3) Opt-out TVP with low customer responsiveness; and 4) Opt-out TVP with high customer responsiveness.

Key Assumptions

Key assumptions used to estimate potential savings for the four scenarios are summarized in Table 5-6. For this illustrative rate design, National Grid assumed all residential customers would have the ability to participate in the TVP program. Customers would have the ability to Opt-out of TVP, with an assumption of 20% used in the analysis. The 20% assumption is conservative, as the Company has experienced only a less than 10% opt-out in the National Grid Smart Energy Solutions pilot in Massachusetts. Customer participation is also dependent on the pace of meter deployment, which is assumed to be 20% annually beginning in fiscal year 2019. Steady state enrollment in the TVP is assumed to occur after year 10. This acknowledges and assumes that while all meters scheduled for a year may be deployed, customer behaviors are slower to change, implying lower capacity and energy savings in the early years of the program. As customers become familiar with the new TVP program, more customers will continuously become active in CPP load reductions. Different levels of customer engagement and responsiveness to the rates are captured in the low and high scenarios.

Table 5-6: Assumptions

Program Type	Scenario	Customer Participation	Meter Deployment Rate/Year	Years to Steady State	CPP Peak Load Reduction	TOU OnPeak Energy Reduction
Opt-In	Low	20%	20%	10	8%	4%
Opt-In	High	20%	20%	10	18%	8%
Opt-Out	Low	80%	20%	10	8%	4%
Opt-Out	High	80%	20%	10	18%	8%

The following graph is from page 23 of the "Smart Grid Consumer Collaborative: Smart Grid Economic and Environmental Benefits," October 2013. This data was used as the basis of the Company assumptions in Table 5-6.

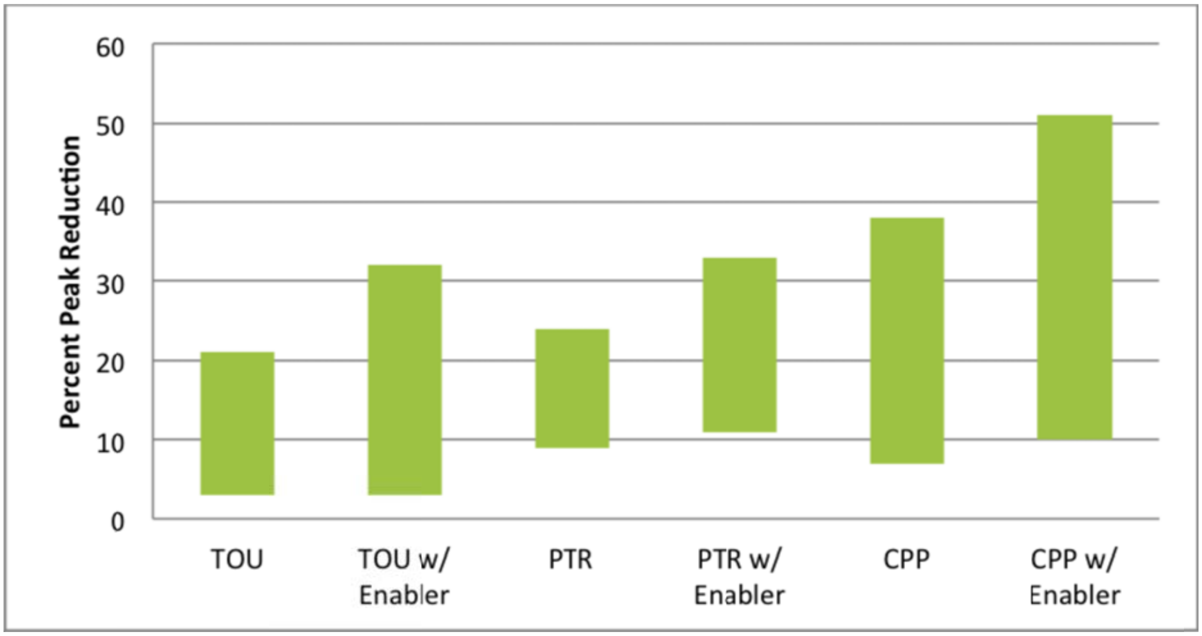

Figure 5-1: TOU Percent Reductions

Figure 5-1 depicts TOU percent reductions of 4% to 21%; however, the Company is using a lower range of 4% to 8% because some of the reductions included in the underlying data include "load shifting", and this analysis assumed only savings from reductions in energy consumption. The Company's assumption is conservative in the fact that additional customer savings do occur from load shifting from higher priced Onpeak hours to lower priced Offpeak hours.

For CPP, the data in Figure 5-1 shows a range of 8% to a high of 37%. The Company is using a range of 8% to 18%. A lower upper bound of the range is used by the Company because the CPP event threshold is 27,500 MW, which is a 14% reduction from the 2016 actual NYISO peak of 32,706 MW. In other words, the "new NYISO peak" would be 27,500 MW, since no CPP events would be called above that specific peak load on any given summer day. Thus, any further reductions cannot be achieved without altering the CPP program to call events at a lower upper threshold. Although that reduction would only be 14%, the forecast NYISO peak was 33,360 MW, which equates to a forecast 17.6% reduction. Thus, the Company is assuming an 18% upper bound reduction for CPP.

5.3.3.5 Supply Cost Savings

CPP Calculation

This benefit calculation is generally comprised of forecasted annual peak load multiplied by achievable load reduction percentage (based on AMI deployment and CPP adoption) multiplied by anticipated AGCC dollars per kW avoided.

For additional detail, below are the cost components that impact the calculation:

a) Forecasted peak load, which could be impacted by CPP
b) Maximum potential CPP load reduction (ranges from 8% to 18%,as noted above)
c) Transmission Thermal Losses
d) Opt-Out of the program rates (%)
e) Years to Steady State participation (10 years)
f) Time Varying Rate adoption schedule
    a. CPP / TOU Maximum Steady State Adoption = 80% for residential customers
    b. CPP / TOU Minimum Steady State Adoption = 20% for residential customers
g) Capacity Prices (NYISO ROS ICAP) Annual AGCC $ per kW per month

TOU Calculation
This benefit calculation is generally comprised of forecasted load during peak hours multiplied by achievable load reduction percentage (based on AMI deployment and TOU adoption) multiplied by avoided average fuel costs per MWh of generation.

For additional detail, below are the cost components that impact the calculation:

a) Forecasted load, which could be impacted by CPP
b) OnPeak Load factor
c) Transmission Thermal Losses
d) OnPeak Load Reduction Factor (ranges from 4% to 8%).
e) Opt-Out rates (20%)
f) Years to Steady State participation (10 years)
g) Time Varying Rate adoption schedule. This acknowledges and assumes that while all meters scheduled for a year may be deployed, customer behaviors are slower to change. This schedule further moderates the peak reductions which could be expected for given years early in the TVP program rollout.
    a. CPP / TOU Maximum Steady State Adoption = 80% for residential customers
    b. CPP / TOU Minimum Steady State Adoption = 20% for residential customers
h) Retail Market Prices of Energy (LBMP)

5.3.3.6 Forecasted Savings

A summary of the total savings over 20 years is shown in Table 5-7 below. The savings represent net savings as they are offset by the costs to market and administer the program assumed to be 20% of the gross benefits. The range of savings is from a low of $42 million to a high of $365 million (with a discount rate of 6.85%).

Table 5-7: Summary of Total TVP Savings over 20 Years ($million)

	WACC (after tax)		RIM Test (pre-tax)	
NPV ($millions)	**6.85%**		**9.79%**	
Opt-In	**Low**	**High**	**Low**	**High**
CPP Savings	$26	$58	$18	$41
TOU Savings	$17	$33	$12	$23
Total Savings	$42	$91	$30	$64
Opt-Out	**Low**	**High**	**Low**	**High**
CPP Savings	$103	$232	$72	$163
TOU Savings	$66	$133	$46	$92
Total Savings	$170	$365	$119	$255

5.3.4 Customer Benefits Summary

Table 5-8: Customer Benefits ($million)

Customer	20-Year NPV (FY19$)
Volt-VAR Optimization	$21.76
Energy Insights/High Usage Alerts	$53.62
Time Varying Pricing*	$42.44
Total	$117.82

* Opt-In Low Savings Scenario

5.4 Societal Benefits

5.4.1 Reduction in Greenhouse Emissions

AMI will produce societal benefits through the reduction of greenhouse gas emissions. Reductions will occur as a result of energy conservation enabled by AMI, including enhanced access to usage information and usage alerts, education, and pricing programs. Greenhouse gas emissions will also be reduced by eliminating the need for vehicle trips to read meters, connect and disconnect service, and investigate service anomalies.

5.4.2 Societal Benefits Summary

Table 5-9: Societal Benefits ($million)

Societal (CO2 Emission Reductions)	20-Year NPV (FY19$)
AMR Meter Reading	$7.62
Meter Investigations	$2.75
Remote Connect and Disconnect	$32.88
Energy Insights/High Usage Alerts	$23.48

Societal (CO2 Emission Reductions)	20-Year NPV (FY19$)
Time Varying Pricing	$5.99
Total	$72.72

5.5 Revenue Benefits

5.5.1 Reduction in Theft of Service

Smart meter technology combines greater frequency of readings with sophisticated algorithms to ensure that electric and gas consumption is accurate. AMI provides tamper alarms after detecting usage that attempts to bypass the meter, and also produces customer level data that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service. If discrepancies are proven to be theft, the Company can take action to address the situation, thus minimizing a cost that would normally be socialized across the customer base, thereby saving other customers money.

Per a report from the Electric Power Research Institute (EPRI)[4], today's well managed utilities with proactive revenue protection programs will experience average revenue losses from all non-technical sources (excluding bad debt) of 1.5%, with 3% representing the higher end of the range. This same report explains that AMI with meter data management can mitigate many of the factors contributing to these losses. For the purposes of this business case, we have utilized a conservative assumption that AMI implementation will reduce non-technical revenue losses (excluding bad debt) by .25%.

5.5.2 Reduction in Write-offs and Inactive Meter Consumption

Bad debt is incurred when National Grid customers are unable or unwilling to pay their billing obligations. National Grid makes every reasonable attempt to collect those outstanding bills. Eventually, this unrealized revenue is classified as a loss and is written off and spread across all customers. Smart meter's ability to remotely disconnect service, within the existing approved parameters and in consideration of all consumer protection processes, will reduce these socialized costs. Although the smart meters cannot entirely eliminate bad debt write-offs, the remote disconnect function can reduce the period between when an electric customer defaults on payment to when their meter is actually disconnected, thus reducing the loss incurred. In time the impact of this functionality will prompt a change in customer behavior, resulting in a significant reduction in overall bad debt and operational expense. This will improve the customer experience due to fewer collection activities such as mailings, phone calls, and field visits.

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[4] Electric Power Research Institute, *Advance Metering Infrastructure Technology – Limiting Non-Technical Distribution Losses in the Future*, December 2008, Pages 1-6, 1-14.

The ability of Smart Meters to remotely connect and disconnect services drives benefits that result from costs associated with inactive meters or “soft off” unoccupied premises. National Grid estimates that there are regularly around 170,000 inactive electric meters within its service territory. A soft off inactive meter with use occurs when electric services are used while the linked account is inactive. For instance, if a customer moves into a previously unoccupied property without notifying the company to change the account name, use on that account will not be billed until the meter is read and use is discovered. The company then investigates to start a new account. The interim period of time between inactive meter activity and confirming a new account name can rarely be billed as the actual consumer cannot be fully verified. The ability of smart meters to read usage daily and be remotely disconnected will minimize inactive meter usage on vacant property. As a result, National Grid can reduce these unbillable energy costs that were previously disseminated across the entire customer base.

5.5.3 Revenue Benefits Summary

Table 5-10: Revenue Benefits ($million)

Revenue Benefits	20-Year NPV (FY19$)
Reduction in Theft of Service	$58.16
Reduction in Write-offs and Inactive Meter Consumption	$88.91
Total	$147.07

5.6 Additional Synergies/Coordination Benefits

The components, capabilities, costs, and benefits articulated in the prior sections all align to the core vision of AMI for near-term implementation. Other capabilities and use cases were also contemplated but were determined to be out of scope. As such, no costs or benefits have been defined for these capabilities. However, as AMI deploys, stabilizes, and matures, the preliminary vision can be expanded upon in the following ways.

5.6.1 Water Utility/Municipality Revenue Opportunities with Joint Use

Electric utilities have pursued the concept of “Joint Use” for many years through the use of shared infrastructure like utility poles that support electric, telephone, and cable television lines. Applied to metering technology, the technical umbrella of National Grid’s proposed infrastructure could be leveraged to support the metering efforts that overlap with water utilities. While water meters themselves could likely be procured and installed by the respective water agency, wireless radios, backhaul, and back-office validation systems could be owned by National Grid but provided as “Metering-As-A-Service” to interested jurisdictions. In this way, while REV is strictly applicable to energy, the concepts of greater customer information and empowered decision making can be expanded as a more holistic capability for customers located in Upstate New York.

5.6.2 AMI for Streetlights and Ancillary Devices

Many metering technology vendors, in addition to numerous lighting control technology applications offer metering capabilities for street light infrastructure which complements the other proposed metering capabilities. Street lights have a universal, industry standard receptacle for a light sensitive photoelectric control that is used to facilitate the changing dusk to dawn operating schedule throughout the year. This lighting control can be replaced with a new control device that incorporates dedicated solid state AMI meter chip technology. At a minimum, this control device can integrate with the metering mesh to transition street lighting from an unmetered to a metered billing application.

The increasing customer demand for this metering functionality is being fostered by the instant on/off and dimming capabilities of solid state lighting technology (i.e. light emitting diode (LED's)) to provide customized, variable operating schedules and illumination levels based on application needs. The additional energy savings of these tailored usage applications beyond the savings achieved through conversion from legacy lighting technologies cannot be realized through the use of limited fixed operating schedules that conform to present analytic billing methods. Additionally, these devices provide additional communication contact nodes to reinforce and strengthen data routing. Further, by virtue of the inherent elevation and location logistics, the additional nodes can also reduce communication hop counts and minimize the urban concrete canyon effects by increasing the number of direct communications to the nearest wireless router.

Street Light AMI also has several benefits independent of the broader metering platform. These include:

- Preemptive maintenance based on:
    - Luminaire diagnostics used to identify imminent failure characteristics for; lamps, ignitor, ballast, surge suppression and photocontrol sensor for timely repairs to avoid "outages" or "day-burners";
    - Circuitry diagnostics used to identify electric operating conditions;
    - Detection of errant (stray) voltage conditions and inadequate grounding capacity;
    - Minimizes customer/company interaction for operation condition reporting;
- Promotes the application and accurate energy metering of advanced technologies such as; WiFi, surveillance and detection cameras (e.g. license plate, parking space, "red light", etc.), sensors (e.g. Motion, temperature, humidity, hazardous chemicals, radiation, etc.), distributed antenna and small cell technology, interactive parking meters, vehicle charging stations and other emergency notification systems;
- Establishes a real-time, global position for all street lighting and ancillary device locations;
- Supports active asset management of street lighting and associated infrastructure for accurate inventory and billing requirements; and
- Enhances customer accessibility of street lighting /device information through a secure interactive internet interface for: inventory information, operational

scheduling/dimming, installation/removal/relocation requests and scheduling, maintenance service reporting and performance

- Enables customer control of advanced lighting technologies facilitating dynamic use of the lights while experiencing actual energy consumption billing optimizing all energy efficiencies.

5.6.3 Outage Management

An additional benefit of core smart meter technology is the ability to report an outage in near real time. Although individual smart meters are electrically powered, they have enough battery life to signal the network and operational systems of a power loss. This ability has several advantages over the current system of monitoring substations for very large power changes that would indicate an outage and rely on customer calls to pinpoint. Smart meters near real-time power outage notification allow the system operators to assess outage characteristics more quickly, have more extensive situational awareness, and take steps to restore power more efficiently. Furthermore, once power has been restored, smart meters can be dynamically pinged to assess whether the entire outage has been restored or if additional work needs to be done to restore nested outages.

5.6.4 Gas Remote Service Valve

Gas remote service shutoff valves can be integrated with the AMI solution. Remote service valves with flood sensors that automatically shut off gas to structures that experience flooding and provide an accurate count of services impacted by the flooding - will enable improved emergency response in the event of flooding. This targeted approach shuts down only the services affected by flooding (as opposed to the larger gas service districts) and sends alerts to the customers impacted, isolating the system and alerting the Company of the loss of service to our customers in real time. This will enable improved management of storm restoration with specific focus on the affected customers. This program will also facilitate swift decision making focused upon affected regions, thus generating efficient execution of service restoration work and allowing improved customer satisfaction while further ensuring the safety and reliability of the system. Remote Service Shutoff Valves without flood sensors can also be installed, allowing for remote disconnect for safety reasons such as residential methane detection alarms, gas leaks, and customer natural gas calls.

5.6.5 Residential Methane Detectors

Residential Methane Detectors (RMD) equipped with communication devices, also known as Smart Residential Methane Devices, are currently in research and development in support of deployment. The RMD can be integrated with the AMI solution. Smart RMD's will be able to send a notification to National Grid in the event the device senses methane at a customer location through a fixed communication network, allowing National Grid to respond with or without a customer call. In conjunction with the remote service valve, National Grid will have the ability to turn off a customer service remotely when methane is detected, ensuring safety prior a potential leak being investigated. Systematic methane detection across multiple customer locations in a common area in the event multiple devices sense methane can be investigated as well. Due to an RMD's nature to detect any type of methane, any type of leak within the residence will be detected, including customer owned equipment and piping. This is especially critical in multiple unit dwellings (i.e.-apartment buildings, multistory structures, etc.).

6 BENEFIT COST ANALYSIS

6.1 Benefits and Costs Included in Each BCA Test Perspective

The primary methodology used by utilities to assess the appropriateness of AMI investment and related programs is benefit cost analysis ("BCA"). As specified by the BCA[5] Whitepaper, three distinct tests are to be included in the BCA results:

- **Societal Cost Test (SCT)** – Is the utility, state, or nation better off as a whole (i.e. do the benefits, including externalities, outweigh the costs)?
- **Utility Cost Test (UCT)** – Will the cost to the utility/program administrator increase (i.e. is the project self-funding or are additional funds needed)?
- **Rate Impact Measure (RIM)** – Will volumetric utility rates increase?

BCA is often applied on a forward looking basis to projects with large initial costs, but having benefits that will continue over several years. The BCA tests are recommended to help evaluate proposals from a variety of standpoints. Each of the tests attempts to address the complexities involved in large scale investments with a unique understanding of how utility expenses translate into tangible savings and improvement for all impacted parties.

The primary purpose of the RIM test is to provide an indication of how AMI will affect customer rates. The UCT does not include benefits experienced by customers or externalities, but does include costs such as customer incentives since the utility would need to determine a way to fund these programs. The SCT counts operational benefits to a utility, as well as benefits experienced by customers, reductions in resource requirements (e.g. generation capacity, energy use) and reductions in externalities such as carbon emissions. It does not treat transfers between parties as costs.

Tables 6-1 and 6-2 below summarize the various AMI benefits and costs that are included in each of the BCA test perspectives.

Table 6-1: Benefits Included in BCA Tests

Category	Benefit	Societal	Utility	Ratepayer
Avoided O&M Costs	AMR Meter Reading	X	X	X
	Meter Investigation	X	X	X
	Remote Connect and Disconnect	X	X	X
	Reduction in Damage Claims	X	X	X
Avoided AMR Costs	Capital	X	X	X
	Operations & Maintenance	X	X	X
Customer	Volt-VAR Optimization	X	X	X
	Energy Insights/High Usage Alerts	X	X	X
	Time Varying Pricing	X	X	X

[5] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) ("BCA Order").

Category	Benefit	Societal	Utility	Ratepayer
Societal	Reduction in Greenhouse Gas Emissions	X		
Revenue	Reduction in Theft of Service			X
	Reduction in Write-offs & Inactive Meter Consumption			X

Table 6-2: Costs Included in BCA Tests

Category	Cost	Societal	Utility	Ratepayer
Meter Equipment and Installation	Electric Meters	X	X	X
	Gas ERTs	X	X	X
	Meter and ERT Inventory	X	X	X
	Support Infrastructure	X	X	X
Communication Equipment and Installation	Network Equipment and Install	X	X	X
	Backhaul	X	X	X
IT Platform and Ongoing IT Operations	AMI Head-end and Meter Data Management Systems	X	X	X
	Customer Service System	X	X	X
	Customer Engagement Products and Services	X	X	X
	IS Infrastructure	X	X	X
	Cyber Security	X	x	X
Project Mgmt. and Ongoing Business Operations	Project Management	X	X	X
	Equipment and Installation Refresh Cost	X	X	X
	Ongoing Business Management	X	X	X
	Customer Engagement Cost	X	X	X
Other	Reduction in Theft of Service			X
	Bad Debt			X

6.2 Discount Rates

The present value of costs and benefits are discounted back to fiscal year 2019 (when costs are first incurred) using the National Grid weighted average cost of capital ("WACC") as the discount rate. The pre-tax WACC (9.79%) is used for the UCT and RIM, whereas the after-tax WACC (6.85%) is used for the SCT since taxes are considered income transfers and excluded from the societal test.

6.3 Summary of Benefits and Costs

The primary emphasis is on the societal test, as this perspective is most critical from a public policy standpoint. Four societal cost test scenarios are presented in Table 6-3 below based on the range of time variant pricing benefits described and included in Section 5.3.3 above.

Table 6-3: Societal Test Benefits and Costs

Category	Component	Scenario 1 Opt-in w/ Low Savings	Scenario 2 Opt-in w/ High Savings	Scenario 3 Opt-out w/ Low Savings	Scenario 4 Opt-out w/ High Savings
Costs	Meter Equipment and Installation	$292.91	$292.91	$292.91	$292.91
	Communication Equipment and Installation	$18.92	$18.92	$18.92	$18.92
	IT Platform and Ongoing IT	$226.19	$226.19	$226.19	$226.19
	Project Management and Ongoing Business Operations	$69.54	$69.54	$69.54	$69.54
	Total Costs	$607.98	$607.98	$607.98	$607.98
Benefits	Avoided O&M Costs	$117.79	$117.79	$117.79	$117.79
	Avoided AMR Costs	$275.60	$275.60	$275.60	$275.60
	Customer	$117.82	$166.38	$245.38	$440.38
	Societal	$72.72	$78.70	$90.67	$114.62
	Total Benefits	$583.93	$638.47	$729.44	$948.39
B/C Ratio	Societal Cost Test	0.96	1.05	1.20	1.56

Benefit-cost analysis results for all three tests; the Societal Cost Test (SCT), Utility Cost Test (UCT), and Rate Impact Measure (RIM), are included in Table 6-4 below. Four scenarios are presented representing the time-variant pricing scenarios presented in section 5.3.3.

Table 6-4: BCA Test Results

Pricing Options	SCT	UCT	RIM
Opt-in/Low Savings	0.96	0.81	1.02
Opt-in/High Savings	1.05	0.90	1.14
Opt-out/Low Savings	1.20	1.06	1.34
Opt-out/High Savings	1.56	1.44	1.82

The results demonstrate the proposed AMI program meets the SCT test for all but the Opt-in/Low Savings scenario. The RIM test results are positive across all scenarios demonstrating the added value provided by the revenue area benefits of reduced theft of service and bad debts.

7 REVENUE REQUIREMENTS/PRICING IMPACTS

Based on a 20 year levelized revenue requirement, the estimated average monthly bill impact, excluding benefits, is estimated at $2.71 for electric and $2.13 for gas.

8 CONCLUSION

The BCA SCT, UCT and RIM results support the pursuit of full AMI deployment across National Grid's electric and gas service territory. On a societal cost test basis the AMI programs net present value costs over the 20-year evaluation period are estimated at $608 million while the benefits range from $584 million (low case) to $948 million (high case). The net benefits may be enhanced if other National Grid companies implement AMI, as it may be possible to share a portion of the IT platform and ongoing costs. In addition, a number of future benefits opportunities were also identified that the Company expects to explore over time.

AMI will provide customers with the knowledge and tools needed to better inform their energy decisions and reduce their energy costs. At the same time, AMI will modernize the Company's system, enabling improved planning and operations, and the integration of increasing levels of DER to support a cleaner, more resilient and efficient system, consistent with the Commission's REV objectives and New York State's clean energy goals.

Exhibit __ (AMI-3)

Schedule of AMI costs and benefits

Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
AMI RATE CASE (COMBINED)								
2	Total benefit from eliminated AMR meter readers	Opex	Avoided O&M	$ 43.06	$ -	$ -	$ -	$ 98.21
3	Total benefit from eliminated AMR meter reader vehicle costs	Opex	Avoided O&M	$ 2.72	$ -	$ -	$ -	$ 6.20
4	Total CO2 benefit from eliminated AMR reading vehicle emissions	Emissions	Net Avoided GHGs	$ 7.62	$ -	$ -	$ -	$ 16.93
5	Total benefit from reduction of meter investigations	Opex	Avoided O&M	$ 5.47	$ -	$ -	$ -	$ 12.48
6	Total benefit from remote metering capabilities	Opex	Avoided O&M	$ 57.08	$ -	$ -	$ -	$ 130.19
11	Total benefit from mitigation / reduction of damage claims	Opex	Avoided O&M	$ 9.46	$ -	$ -	$ -	$ 22.46
14	Total benefit from reduction of distribution losses (SM)	Opex	Avoided Distribution Losses	$ 21.76	$ -	$ -	$ -	$ 56.68
								$ -
16	Total fuel savings	Revenue	Avoided Energy	$ 53.62	$ -	$ -	$ 0.95	$ 120.56
17	Total CO2 savings from fuel savings, electric	Losses	Net Avoided GHGs	$ 23.48	$ -	$ -	$ 0.60	$ 49.70
								$ -
18	Total CO2 benefit from reduction of meter investigations	Emissions	Net Avoided GHGs	$ 2.75	$ -	$ -	$ -	$ 6.11
19	Total CO2 benefit from remote metering capabilities	Emissions	Net Avoided GHGs	$ 32.88	$ -	$ -	$ -	$ 73.01
								$ -
26	Low-End Red. & Opt-In Total benefit from Critical Peak Pricing (CPP) peak shaving	Opex	Avoided Generation Capacity	$ 25.82	$ -	$ -	$ -	$ 64.90
27	Low-End Red. & Opt-In Total benefit from Avoided Energy due to Time-of-Use Program	Opex	Avoided Energy	$ 16.62	$ -	$ -	$ -	$ 42.33
28	Low-End Red. & Opt-In Total CO2 savings from Avoided Energy due to Time-of-Use Program	Emissions	Net Avoided GHGs	$ 5.99	$ -	$ -	$ -	$ 15.03
								$ -
100	Electric AMR Equipment Meter Replacement	Capex	Avoided AMR Capital	$ 110.35	$ -	$ -	$ 35.98	$ 112.55
101	Avoided AMI gas ERT / module equipment cost	Capex	Avoided AMR Capital	$ 30.26	$ -	$ -	$ 7.89	$ 32.84
102	Avoided AMI electric meter installation cost - Capex portion	Capex	Avoided AMR Capital	$ 59.34	$ -	$ -	$ 14.69	$ 65.30
103	Avoided AMI gas ERT / module installation cost - Capex portion	Capex	Avoided AMR Capital	$ 13.83	$ -	$ -	$ 3.32	$ 15.33
105	Avoided AMI demonstration period cost	Opex	Avoided AMR O&M	$ 1.03	$ -	$ 1.17	$ -	$ -
110	Avoided AMI network engineering, design, contracting cost	Capex	Avoided AMR Capital	$ 0.09	$ -	$ 0.10	$ -	$ -
111	Avoided Network communications equipment cost, Electric Meters	Capex	Avoided AMR Capital	$ 0.52	$ -	$ -	$ 0.14	$ 0.57
112	Avoided Network communications equipment cost, Gas Meters	Capex	Avoided AMR Capital	$ 0.30	$ -	$ -	$ 0.08	$ 0.32
113	Avoided Network communications installation cost, Electric Meters	Capex	Avoided AMR Capital	$ 0.04	$ -	$ -	$ 0.01	$ 0.05
114	Avoided Network communications installation cost, Gas Meters	Capex	Avoided AMR Capital	$ 0.02	$ -	$ -	$ 0.01	$ 0.03
115	Avoided Network communications LTE backhaul cost, Electric Meters	Opex	Avoided AMR O&M	$ 0.35	$ -	$ -	$ 0.01	$ 0.77
116	Avoided Network communications LTE backhaul cost, Gas Meters	Opex	Avoided AMR O&M	$ 0.20	$ -	$ -	$ 0.00	$ 0.44
118	Avoided Network communications equipment cost upgrade	Capex	Avoided AMR Capital	$ 0.69	$ -	$ -	$ -	$ 1.33
121	Avoided Total AMI External Project Management labor cost - Capex portion	Capex	Avoided AMR Capital	$ 0.05	$ -	$ 0.03	$ 0.02	$ -
123	Avoided Total cost from call center and account payable volume, implementation	Opex	Avoided AMR O&M	$ 4.35	$ -	$ 0.24	$ 1.08	$ 4.47
124	Avoided Total AMI Internal Project Management Leadership Staff - Capex portion	Capex	Avoided AMR Capital	$ 1.73	$ -	$ 0.43	$ 0.44	$ 1.38
126	Avoided AMI electric meter installation cost - COR portion	COR	Avoided AMR Capital	$ 4.67	$ -	$ -	$ 1.16	$ 5.14
127	Avoided AMI gas ERT / module installation cost - COR portion	COR	Avoided AMR Capital	$ 7.45	$ -	$ -	$ 1.79	$ 8.26
128	Avoided Total AMI External Project Management labor cost - Opex portion	Opex	Avoided AMR O&M	$ 0.14	$ 0.06	$ 0.08	$ 0.01	$ -
129	Avoided Total AMI Internal Project Management Leadership Staff - Opex portion	Opex	Avoided AMR O&M	$ 0.20	$ 0.21	$ -	$ -	$ -
131	Avoided AMI gas meter equipment cost	Capex	Avoided AMR Capital	$ 1.88	$ -	$ -	$ 2.29	$ -
132	Avoided AMI dual fuel with gas meter related installation cost - Capex portion	Capex	Avoided AMR Capital	$ 1.41	$ -	$ -	$ 1.72	$ -
133	Avoided AMI dual fuel with gas meter related installation cost - COR portion	COR	Avoided AMR Capital	$ 0.40	$ -	$ -	$ 0.49	$ -
134	Avoided AMI inventory equipment cost	Capex	Avoided AMR Capital	$ 4.13	$ -	$ -	$ 1.08	$ 4.49
								$ -
203	Avoided Total CMS Deployment Center, Facility cost	Capex	Avoided AMR Capital	$ 3.26	$ -	$ -	$ 1.06	$ 3.33

Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
	AMI RATE CASE (COMBINED)							
204	Avoided Total CMS Back Office & Clerical cost	Capex	Avoided AMR Capital	$ 5.43	$ -	$ -	$ 1.77	$ 5.54
205	Avoided Total Service Representative Tools / Uniform cost	Capex	Avoided AMR Capital	$ 0.35	$ -	$ -	$ 0.21	$ 0.25
206	Avoided Total Installed meter Quality Assurance / Quality Check cost	Capex	Avoided AMR Capital	$ 1.22	$ -	$ -	$ 0.40	$ 1.25
207	Avoided Total CMS Deployment Coordination Labor cost	Capex	Avoided AMR Capital	$ 1.77	$ -	$ -	$ 0.58	$ 1.80
208	Avoided CMS Field Installer Initial Training	Capex	Avoided AMR Capital	$ 0.92	$ -	$ 0.53	$ 0.55	$ -
209	Avoided Total CMS Cellular Communication cost	Capex	Avoided AMR Capital	$ 0.29	$ -	$ -	$ 0.10	$ 0.30
210	Avoided Handheld Devices cost	Capex	Avoided AMR Capital	$ 0.01	$ -	$ -	$ 0.01	$ -
								$ -
302	Avoided Total System Testing management, internal resources	Capex	Avoided AMR Capital	$ 0.06	$ -	$ 0.05	$ 0.02	$ -
								$ -
400	Avoided Total Customer Engagement Program Design cost	Opex	Avoided AMR O&M	$ 0.12	$ 0.06	$ 0.07	$ -	$ -
404	Avoided Total Content Development, Targeted Messaging cost	Opex	Avoided AMR O&M	$ 6.32	$ -	$ 0.79	$ 1.62	$ 5.88
								$ -
540	Avoided FCS Costs	Opex	Avoided AMR O&M	$ 4.92	$ 0.06	$ 0.16	$ 0.29	$ 9.45
								$ -
600	Avoided Cyber Security Project Capex Initial	Capex	Avoided AMR Capital	$ 1.90	$ -	$ 1.27	$ 0.62	$ 0.36
601	Avoided Cyber Security Project Opex Initial	Opex	Avoided AMR O&M	$ 0.75	$ -	$ 0.53	$ 0.25	$ 0.10
602	Avoided Cyber Security Project RTB O&M	Opex	Avoided AMR O&M	$ 1.95	$ 0.00	$ 0.21	$ 0.16	$ 3.56
603	Avoided Cyber Security Refresh / Removal Capital	Capex	Avoided AMR Capital	$ 1.96	$ -	$ -	$ -	$ 4.44
604	Avoided Cyber Security Capital Refresh / Removal Opex	Opex	Avoided AMR O&M	$ 0.92	$ -	$ -	$ -	$ 2.01
	Total Benefit			**$ 583.93**	**$ 0.40**	**$ 5.70**	**$ 81.41**	**$ 1,006.29**
100	AMI electric meter equipment cost	Capex	Meters	$ 153.78	$ -	$ -	$ 40.12	$ 166.89
101	AMI gas ERT / module equipment cost	Capex	Meters	$ 30.26	$ -	$ -	$ 7.89	$ 32.84
102	AMI electric meter installation cost - Capex portion	Capex	Installation	$ 59.34	$ -	$ -	$ 14.69	$ 65.30
103	AMI gas ERT / module installation cost - Capex portion	Capex	Installation	$ 13.83	$ -	$ -	$ 3.32	$ 15.33
104	AMI failed meter equipment replacement cost	Capex	Meters	$ 2.36	$ -	$ -	$ -	$ 5.40
105	AMI demonstration period cost	Opex	Meters	$ 1.37	$ -	$ 1.56	$ -	$ -
110	AMI network engineering, design, contracting cost	Capex	Communications	$ 0.09	$ -	$ 0.10	$ -	$ -
111	Network communications equipment cost, Electric Meters	Capex	Communications	$ 2.61	$ -	$ -	$ 0.68	$ 2.84
112	Network communications equipment cost, Gas Meters	Capex	Communications	$ 1.48	$ -	$ -	$ 0.38	$ 1.60
113	Network communications installation cost, Electric Meters	Capex	Communications	$ 0.21	$ -	$ -	$ 0.05	$ 0.23
114	Network communications installation cost, Gas Meters	Capex	Communications	$ 0.12	$ -	$ -	$ 0.03	$ 0.13
115	Network communications LTE backhaul cost, Electric Meters	Opex	Communications	$ 1.77	$ -	$ -	$ 0.04	$ 3.85
116	Network communications LTE backhaul cost, Gas Meters	Opex	Communications	$ 1.01	$ -	$ -	$ 0.02	$ 2.20
117	AMI meter cellular service cost, Electric Meters	Opex	Communications	$ 4.38	$ -	$ -	$ 0.10	$ 9.57
118	Network communications equipment cost upgrade	Capex	Communications	$ 3.43	$ -	$ -	$ -	$ 6.66
119	AMI communications failed equipment replacement cost	Capex	Communications	$ 0.48	$ -	$ -	$ -	$ 1.10
120	AMI communications equipment O&M cost (outside warranty)	Opex	Communications	$ 1.05	$ -	$ -	$ -	$ 2.31
121	Total AMI External Project Management labor cost - Capex portion	Capex	Project Management	$ 0.48	$ -	$ 0.34	$ 0.23	$ -
123	Total cost from call center and account payable volume, implementation	Opex	Back Office	$ 5.79	$ -	$ 0.33	$ 1.45	$ 5.96
124	Total AMI Internal Project Management Leadership Staff - Capex portion	Capex	Project Management	$ 1.73	$ -	$ 0.43	$ 0.44	$ 1.38
125	Total AMI Internal Project Management Business Support - Capex portion	Capex	Project Management	$ 1.17	$ -	$ 1.34	$ -	$ -

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
	AMI RATE CASE (COMBINED)							
126	AMI electric meter installation cost - COR portion	COR	Installation	$ 4.67	$ -	$ -	$ 1.16	$ 5.14
127	AMI gas ERT / module installation cost - COR portion	COR	Installation	$ 7.45	$ -	$ -	$ 1.79	$ 8.26
128	Total AMI External Project Management labor cost - Opex portion	Opex	Project Management	$ 1.38	$ 0.61	$ 0.81	$ 0.13	$ -
129	Total AMI Internal Project Management Leadership Staff - Opex portion	Opex	Project Management	$ 0.20	$ 0.21	$ -	$ -	$ -
130	Total AMI Internal Project Management Business Support- Opex portion	Opex	Project Management	$ 0.71	$ 0.76	$ -	$ -	$ -
131	AMI gas meter equipment cost	Capex	Meters	$ 1.88	$ -	$ -	$ 2.29	$ -
132	AMI dual fuel with gas meter related installation cost - Capex portion	Capex	Installation	$ 1.41	$ -	$ -	$ 1.72	$ -
133	AMI dual fuel with gas meter related installation cost - COR portion	COR	Installation	$ 0.40	$ -	$ -	$ 0.49	$ -
134	AMI inventory equipment cost	Capex	Meters	$ 4.64	$ -	$ -	$ 1.21	$ 5.04
135	Professional Services - Field Deployment Support Workstream cost	Capex	Project Management	$ 7.12	$ -	$ 0.49	$ 2.25	$ 6.75
136	Professional Services - Field Deployment Support Workstream Travel Expenses cost	Opex	Project Management	$ 1.07	$ -	$ 0.07	$ 0.34	$ 1.01
								$ -
201	Total Back-Office Revenue Assurance Analyst cost	Opex	Meters	$ 7.53	$ -	$ 0.35	$ 0.71	$ 14.41
202	Total cost of theft investigations	Opex	Meters	$ 5.11	$ -	$ -	$ 0.11	$ 11.14
203	Total CMS Deployment Center, Facility cost	Capex	Meters	$ 3.26	$ -	$ -	$ 1.06	$ 3.33
204	Total CMS Back Office & Clerical cost	Capex	Meters	$ 5.43	$ -	$ -	$ 1.77	$ 5.54
205	Total Service Representative Tools / Uniform cost	Capex	Meters	$ 0.35	$ -	$ -	$ 0.21	$ 0.25
206	Total Installed meter Quality Assurance / Quality Check cost	Capex	Meters	$ 1.22	$ -	$ -	$ 0.40	$ 1.25
207	Total CMS Deployment Coordination Labor cost	Capex	Meters	$ 1.77	$ -	$ -	$ 0.58	$ 1.80
208	CMS Field Installer Initial Training	Capex	Meters	$ 0.92	$ -	$ 0.53	$ 0.55	$ -
209	Total CMS Cellular Communication cost	Capex	Meters	$ 0.29	$ -	$ -	$ 0.10	$ 0.30
210	Handheld Devices cost	Capex	Meters	$ 0.01	$ -	$ -	$ 0.01	$ -
								$ -
300	Total AMI Additional Meter Data Services labor cost	Opex	Project Management	$ 7.70	$ -	$ -	$ 0.28	$ 15.60
301	Total AMI Additional Account Maintenance labor cost	Opex	Project Management	$ 3.85	$ -	$ -	$ 0.14	$ 7.80
302	Total System Testing management, internal resources	Capex	Project Management	$ 0.60	$ -	$ 0.52	$ 0.18	$ -
								$ -
400	Total Customer Engagement Program Design cost	Opex	Customer Engagement	$ 0.47	$ 0.26	$ 0.26	$ -	$ -
401	Total Customer Engagement Mass Media marketing cost	Opex	Customer Engagement	$ 3.12	$ -	$ 0.39	$ 0.80	$ 2.90
402	Total Town Hall / Workshop labor cost	Opex	Customer Engagement	$ 0.46	$ -	$ -	$ 0.12	$ 0.50
403	Total Town Hall / Workshop materials cost	Opex	Customer Engagement	$ 0.15	$ -	$ -	$ 0.04	$ 0.17
404	Total Content Development, Targeted Messaging cost	Opex	Customer Engagement	$ 12.65	$ -	$ 1.59	$ 3.24	$ 11.75
405	Total CSR Data Enhancement cost	Opex	Customer Engagement	$ 0.46	$ -	$ 0.52	$ -	$ -
406	Total Satisfaction Surveys cost	Opex	Customer Engagement	$ 6.51	$ -	$ 0.82	$ 1.67	$ 6.05
407	Total Sustainabililty Hub/ Demonstration set-up cost	Opex	Customer Engagement	$ 0.91	$ -	$ 1.04	$ -	$ -
408	Annual Sustainabililty Hub/ Demonstration hub rent cost	Opex	Customer Engagement	$ 0.89	$ -	$ 0.08	$ 0.08	$ 1.64
								$ -
501	CSS Enhancements Capex Cost	Capex	IT & Systems Integration	$ 7.40	$ 5.32	$ 2.76	$ -	$ -
502	Professional Services - Itron Solution Program Management cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
503	Energy Monitoring Portal Opex Cost	Opex	IT & Systems Integration	$ 3.70	$ -	$ 0.16	$ 0.00	$ 8.31
504	Green Button Connect Capex Cost	Capex	IT & Systems Integration	$ 2.70	$ -	$ 3.08	$ -	$ -
505	E-Commerce Marketplace Capex cost	Capex	IT & Systems Integration	$ 4.13	$ 0.92	$ -	$ -	$ 6.87
506	Customer Load Management Opex cost	Opex	IT & Systems Integration	$ 4.15	$ 0.37	$ 0.33	$ 0.34	$ 7.04
513	Telecom Capex cost	Capex	IT & Systems Integration	$ 1.44	$ 0.42	$ 0.37	$ 0.52	$ 0.39

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
AMI RATE CASE (COMBINED)							
514 ESB Capex cost	Capex	IT & Systems Integration	$ 7.41	$ 1.67	$ 2.73	$ 0.49	$ 6.82
516 Information Management Capex cost	Capex	IT & Systems Integration	$ 3.21	$ 1.37	$ 0.85	$ 0.55	$ 1.47
517 Data Lake Capex cost	Capex	IT & Systems Integration	$ 4.89	$ 0.35	$ 0.24	$ 0.34	$ 8.87
518 Professional Services - Itron Systems Implementation Workstream cost	Opex	IT & Systems Integration	[redacted]	[redacted]	[redacted]	[redacted]	$ -
519 SaaS Setup Fees - One Time Setup (Version upgrade and scale-up existing system) cost	Opex	IT & Systems Integration	[redacted]	[redacted]	[redacted]	-	$ -
520 SaaS Fees - Headend Software (OWOCCM, OWOC PM, IEE MDM, IoT FND, FDM) cost	Opex	IT & Systems Integration	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
521 Professional Services - System and Meter Firmware Upgrade cost	Opex	IT & Systems Integration	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
522 Telecom Opex cost	Opex	IT & Systems Integration	$ 0.37	$ 0.08	$ 0.08	$ 0.14	$ 0.14
523 Telecom RTB Cost	Opex	IT & Systems Integration	$ 13.84	$ -	$ 0.64	$ 0.98	$ 27.11
524 ESB Opex cost	Opex	IT & Systems Integration	$ 0.50	$ 0.20	$ 0.28	$ 0.08	$ -
525 ESB RTB Cost	Opex	IT & Systems Integration	$ 9.32	$ 0.10	$ 0.45	$ 0.81	$ 17.75
526 Data Lake Opex cost	Opex	IT & Systems Integration	$ 0.05	$ 0.05	$ -	$ -	$ -
527 Professional Services - Itron Solution Program Management Travel Expenses cost	Opex	IT & Systems Integration	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
528 Professional Services - Itron Systems Implementation Workstream Travel Expenses cost	Opex	IT & Systems Integration	[redacted]	[redacted]	[redacted]	[redacted]	-
529 Green Button Connect Opex Cost	Opex	IT & Systems Integration	$ 0.95	$ 0.18	$ 0.65	$ 0.26	$ -
530 Information Management Opex cost	Opex	IT & Systems Integration	$ 1.32	$ 0.05	$ 0.08	$ 0.08	$ 2.49
531 Information Management RTB Cost	Opex	IT & Systems Integration	$ 3.51	$ -	$ 0.21	$ 0.26	$ 6.75
532 Energy Monitoring Portal RTB Cost	Opex	IT & Systems Integration	$ 0.44	$ -	$ -	$ 0.04	$ 0.88
533 CSS Enhancements Opex Cost	Opex	IT & Systems Integration	$ 0.31	$ 0.23	$ 0.12	$ -	$ -
534 CSS Enhancements RTB Cost	Opex	IT & Systems Integration	$ 0.22	$ -	$ -	$ 0.02	$ 0.44
535 Green Button Connect RTB Cost	Opex	IT & Systems Integration	$ 5.31	$ -	$ -	$ 0.51	$ 10.61
536 Data Lake RTB cost	Opex	IT & Systems Integration	$ 1.50	$ -	$ 0.09	$ 0.14	$ 2.84
537 E-Commerce Marketplace Opex cost	Opex	IT & Systems Integration	$ 0.53	$ -	$ -	$ 0.15	$ 0.89
538 E-Commerce Marketplace RTB cost	Opex	IT & Systems Integration	$ 0.52	$ 0.04	$ 0.04	$ 0.04	$ 0.88
539 Customer Load Management RTB cost	Opex	IT & Systems Integration	$ -	$ -	$ -	$ -	$ -
							$ -
600 Cyber Security Project Capex Initial	Capex	IT & Systems Integration	$ 7.59	$ -	$ 5.08	$ 2.49	$ 1.43
601 Cyber Security Project Opex Initial	Opex	IT & Systems Integration	$ 2.99	$ -	$ 2.13	$ 1.01	$ 0.39
602 Cyber Security Project RTB O&M	Opex	IT & Systems Integration	$ 7.81	$ 0.00	$ 0.86	$ 0.65	$ 14.24
603 Cyber Security Refresh / Removal Capital	Capex	IT & Systems Integration	$ 7.85	$ -	$ -	$ -	$ 17.74
604 Cyber Security Capital Refresh / Removal Opex	Opex	IT & Systems Integration	$ 3.67	$ -	$ -	$ -	$ 8.06
Total Cost			**$ 607.98**	**$ 13.19**	**$ 38.61**	**$ 106.49**	**$ 831.35**
	Capex 100's - 400's		$312.82	$ -	$ 3.75	$ 83.61	$ 337.35
	Opex 100's - 400's		$68.53	$ 1.84	$ 7.81	$ 9.26	$ 96.85
	Total 100's - 400's		$381.35	$ 1.84	$ 11.57	$ 92.87	$ 434.20
	Capex 500's - 600's		$46.63	$ 10.05	$ 15.12	$ 4.38	$ 43.60
	Opex 500's - 600's		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total 500's - 600's		$226.64	$ 11.35	$ 27.04	$ 13.62	$ 397.14
	Total Capex		$359.45	$10.05	$18.88	$88.00	$380.95
	Total Opex		$248.53	$3.14	$19.73	$18.49	$450.40

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
II RATE CASE (ELECTRIC)								
2	Total benefit from eliminated AMR meter readers	Opex	Avoided O&M	$ 31.40	$ -	$ -	$ -	$ 71.60
3	Total benefit from eliminated AMR meter reader vehicle costs	Opex	Avoided O&M	$ 1.98	$ -	$ -	$ -	$ 4.52
4	Total CO2 benefit from eliminated AMR reading vehicle emissions	Emissions	Net Avoided GHGs	$ 5.56	$ -	$ -	$ -	$ 12.34
5	Total benefit from reduction of meter investigations	Opex	Avoided O&M	$ 5.47	$ -	$ -	$ -	$ 12.48
6	Total benefit from remote metering capabilities	Opex	Avoided O&M	$ 57.08	$ -	$ -	$ -	$ 130.19
11	Total benefit from mitigation / reduction of damage claims	Opex	Avoided O&M	$ 6.58	$ -	$ -	$ -	$ 15.89
14	Total benefit from reduction of distribution losses (SM)	Opex	Avoided Distribution Losses	$ 21.76	$ -	$ -	$ -	$ 56.68
								$ -
16	Total fuel savings	Revenue	Avoided Energy	$ 47.23	$ -	$ -	$ 0.79	$ 106.98
17	Total CO2 savings from fuel savings, electric	Losses	Net Avoided GHGs	$ 23.48	$ -	$ -	$ 0.60	$ 49.70
								$ -
18	Total CO2 benefit from reduction of meter investigations	Emissions	Net Avoided GHGs	$ 2.75	$ -	$ -	$ -	$ 6.11
19	Total CO2 benefit from remote metering capabilities	Emissions	Net Avoided GHGs	$ 32.88	$ -	$ -	$ -	$ 73.01
								$ -
26	Low-End Red. & Opt-In Total benefit from Critical Peak Pricing (CPP) peak shaving	Opex	Avoided Generation Capacity	$ 25.82	$ -	$ -	$ -	$ 64.90
27	Low-End Red. & Opt-In Total benefit from Avoided Energy due to Time-of-Use Program	Opex	Avoided Energy	$ 16.62	$ -	$ -	$ -	$ 42.33
28	Low-End Red. & Opt-In Total CO2 savings from Avoided Energy due to Time-of-Use Program	Emissions	Net Avoided GHGs	$ 5.99	$ -	$ -	$ -	$ 15.03
								$ -
100	Electric AMR Equipment Meter Replacement	Capex	Avoided AMR Capital	$ 110.35	$ -	$ -	$ 35.98	$ 112.55
101	Avoided AMI gas ERT / module equipment cost	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
102	Avoided AMI electric meter installation cost - Capex portion	Capex	Avoided AMR Capital	$ 59.34	$ -	$ -	$ 14.69	$ 65.30
103	Avoided AMI gas ERT / module installation cost - Capex portion	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
105	Avoided AMI demonstration period cost	Opex	Avoided AMR O&M	$ 0.75	$ -	$ 0.86	$ -	$ -
110	Avoided AMI network engineering, design, contracting cost	Capex	Avoided AMR Capital	$ 0.07	$ -	$ 0.08	$ -	$ -
111	Avoided Network communications equipment cost, Electric Meters	Capex	Avoided AMR Capital	$ 0.52	$ -	$ -	$ 0.14	$ 0.57
112	Avoided Network communications equipment cost, Gas Meters	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
113	Avoided Network communications installation cost, Electric Meters	Capex	Avoided AMR Capital	$ 0.04	$ -	$ -	$ 0.01	$ 0.05
114	Avoided Network communications installation cost, Gas Meters	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
115	Avoided Network communications LTE backhaul cost, Electric Meters	Opex	Avoided AMR O&M	$ 0.35	$ -	$ -	$ 0.01	$ 0.77
116	Avoided Network communications LTE backhaul cost, Gas Meters	Opex	Avoided AMR O&M	$ -	$ -	$ -	$ -	$ -
118	Avoided Network communications equipment cost upgrade	Capex	Avoided AMR Capital	$ 0.44	$ -	$ -	$ -	$ 0.85
121	Avoided Total AMI External Project Management labor cost - Capex portion	Capex	Avoided AMR Capital	$ 0.04	$ -	$ 0.02	$ 0.02	$ -
123	Avoided Total cost from call center and account payable volume, implementation	Opex	Avoided AMR O&M	$ 3.17	$ -	$ 0.18	$ 0.79	$ 3.26
124	Avoided Total AMI Internal Project Management Leadership Staff - Capex portion	Capex	Avoided AMR Capital	$ 1.26	$ -	$ 0.32	$ 0.32	$ 1.00
126	Avoided AMI electric meter installation cost - COR portion	COR	Avoided AMR Capital	$ 4.67	$ -	$ -	$ 1.16	$ 5.14
127	Avoided AMI gas ERT / module installation cost - COR portion	COR	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
128	Avoided Total AMI External Project Management labor cost - Opex portion	Opex	Avoided AMR O&M	$ 0.10	$ 0.04	$ 0.06	$ 0.01	$ -
129	Avoided Total AMI Internal Project Management Leadership Staff - Opex portion	Opex	Avoided AMR O&M	$ 0.14	$ 0.15	$ -	$ -	$ -
131	Avoided AMI gas meter equipment cost	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
132	Avoided AMI dual fuel with gas meter related installation cost - Capex portion	Capex	Avoided AMR Capital	$ 0.34	$ -	$ -	$ 0.41	$ -
133	Avoided AMI dual fuel with gas meter related installation cost - COR portion	COR	Avoided AMR Capital	$ 0.03	$ -	$ -	$ 0.03	$ -
134	Avoided AMI inventory equipment cost	Capex	Avoided AMR Capital	$ 3.42	$ -	$ -	$ 0.89	$ 3.71
								$ -
203	Avoided Total CMS Deployment Center, Facility cost	Capex	Avoided AMR Capital	$ 2.38	$ -	$ -	$ 0.78	$ 2.43

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
	II RATE CASE (ELECTRIC)							
204	Avoided Total CMS Back Office & Clerical cost	Capex	Avoided AMR Capital	$ 3.96	$ -	$ -	$ 1.29	$ 4.04
205	Avoided Total Service Representative Tools / Uniform cost	Capex	Avoided AMR Capital	$ 0.26	$ -	$ -	$ 0.15	$ 0.18
206	Avoided Total Installed meter Quality Assurance / Quality Check cost	Capex	Avoided AMR Capital	$ 0.89	$ -	$ -	$ 0.29	$ 0.91
207	Avoided Total CMS Deployment Coordination Labor cost	Capex	Avoided AMR Capital	$ 1.29	$ -	$ -	$ 0.42	$ 1.31
208	Avoided CMS Field Installer Initial Training	Capex	Avoided AMR Capital	$ 0.67	$ -	$ 0.39	$ 0.40	$ -
209	Avoided Total CMS Cellular Communication cost	Capex	Avoided AMR Capital	$ 0.21	$ -	$ -	$ 0.07	$ 0.22
210	Avoided Handheld Devices cost	Capex	Avoided AMR Capital	$ 0.00	$ -	$ -	$ 0.01	$ -
								$ -
302	Avoided Total System Testing management, internal resources	Capex	Avoided AMR Capital	$ 0.04	$ -	$ 0.04	$ 0.01	$ -
								$ -
400	Avoided Total Customer Engagement Program Design cost	Opex	Avoided AMR O&M	$ 0.09	$ 0.05	$ 0.05	$ -	$ -
404	Avoided Total Content Development, Targeted Messaging cost	Opex	Avoided AMR O&M	$ 4.61	$ -	$ 0.58	$ 1.18	$ 4.28
								$ -
540	Avoided FCS Costs	Opex	Avoided AMR O&M	$ 3.59	$ 0.04	$ 0.12	$ 0.21	$ 6.89
								$ -
600	Avoided Cyber Security Project Capex Initial	Capex	Avoided AMR Capital	$ 1.38	$ -	$ 0.93	$ 0.45	$ 0.26
601	Avoided Cyber Security Project Opex Initial	Opex	Avoided AMR O&M	$ 0.54	$ -	$ 0.39	$ 0.18	$ 0.07
602	Avoided Cyber Security Project RTB O&M	Opex	Avoided AMR O&M	$ 1.42	$ 0.00	$ 0.16	$ 0.12	$ 2.60
603	Avoided Cyber Security Refresh / Removal Capital	Capex	Avoided AMR Capital	$ 1.43	$ -	$ -	$ -	$ 3.23
604	Avoided Cyber Security Capital Refresh / Removal Opex	Opex	Avoided AMR O&M	$ 0.67	$ -	$ -	$ -	$ 1.47
	Total Benefit			**$ 493.09**	**$ 0.29**	**$ 4.15**	**$ 61.42**	**$ 882.86**
								$ -
								$ -
100	AMI electric meter equipment cost	Capex	Meters	$ 153.78	$ -	$ -	$ 40.12	$ 166.89
101	AMI gas ERT / module equipment cost	Capex	Meters	$ -	$ -	$ -	$ -	$ -
102	AMI electric meter installation cost - Capex portion	Capex	Installation	$ 59.34	$ -	$ -	$ 14.69	$ 65.30
103	AMI gas ERT / module installation cost - Capex portion	Capex	Installation	$ -	$ -	$ -	$ -	$ -
104	AMI failed meter equipment replacement cost	Capex	Meters	$ 2.36	$ -	$ -	$ -	$ 5.40
105	AMI demonstration period cost	Opex	Meters	$ 1.00	$ -	$ 1.14	$ -	$ -
110	AMI network engineering, design, contracting cost	Capex	Communications	$ 0.07	$ -	$ 0.08	$ -	$ -
111	Network communications equipment cost, Electric Meters	Capex	Communications	$ 2.61	$ -	$ -	$ 0.68	$ 2.84
112	Network communications equipment cost, Gas Meters	Capex	Communications	$ -	$ -	$ -	$ -	$ -
113	Network communications installation cost, Electric Meters	Capex	Communications	$ 0.21	$ -	$ -	$ 0.05	$ 0.23
114	Network communications installation cost, Gas Meters	Capex	Communications	$ -	$ -	$ -	$ -	$ -
115	Network communications LTE backhaul cost, Electric Meters	Opex	Communications	$ 1.77	$ -	$ -	$ 0.04	$ 3.85
116	Network communications LTE backhaul cost, Gas Meters	Opex	Communications	$ -	$ -	$ -	$ -	$ -
117	AMI meter cellular service cost, Electric Meters	Opex	Communications	$ 4.38	$ -	$ -	$ 0.10	$ 9.57
118	Network communications equipment cost upgrade	Capex	Communications	$ 2.20	$ -	$ -	$ -	$ 4.26
119	AMI communications failed equipment replacement cost	Capex	Communications	$ 0.31	$ -	$ -	$ -	$ 0.70
120	AMI communications equipment O&M cost (outside warranty)	Opex	Communications	$ 0.67	$ -	$ -	$ -	$ 1.48
121	Total AMI External Project Management labor cost - Capex portion	Capex	Project Management	$ 0.35	$ -	$ 0.24	$ 0.17	$ -
123	Total cost from call center and account payable volume, implementation	Opex	Back Office	$ 4.22	$ -	$ 0.24	$ 1.05	$ 4.34
124	Total AMI Internal Project Management Leadership Staff - Capex portion	Capex	Project Management	$ 1.26	$ -	$ 0.32	$ 0.32	$ 1.00
125	Total AMI Internal Project Management Business Support - Capex portion	Capex	Project Management	$ 0.86	$ -	$ 0.98	$ -	$ -

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
II RATE CASE (ELECTRIC)								
126	AMI electric meter installation cost - COR portion	COR	Installation	$ 4.67	$ -	$ -	$ 1.16	$ 5.14
127	AMI gas ERT / module installation cost - COR portion	COR	Installation	$ -	$ -	$ -	$ -	$ -
128	Total AMI External Project Management labor cost - Opex portion	Opex	Project Management	$ 1.01	$ 0.44	$ 0.59	$ 0.09	$ -
129	Total AMI Internal Project Management Leadership Staff - Opex portion	Opex	Project Management	$ 0.14	$ 0.15	$ -	$ -	$ -
130	Total AMI Internal Project Management Business Support- Opex portion	Opex	Project Management	$ 0.52	$ 0.56	$ -	$ -	$ -
131	AMI gas meter equipment cost	Capex	Meters	$ -	$ -	$ -	$ -	$ -
132	AMI dual fuel with gas meter related installation cost - Capex portion	Capex	Installation	$ 0.34	$ -	$ -	$ 0.41	$ -
133	AMI dual fuel with gas meter related installation cost - COR portion	COR	Installation	$ 0.03	$ -	$ -	$ 0.03	$ -
134	AMI inventory equipment cost	Capex	Meters	$ 3.84	$ -	$ -	$ 1.00	$ 4.17
135	Professional Services - Field Deployment Support Workstream cost	Capex	Project Management	$ 5.19	$ -	$ 0.35	$ 1.64	$ 4.92
136	Professional Services - Field Deployment Support Workstream Travel Expenses cost	Opex	Project Management	$ 0.78	$ -	$ 0.05	$ 0.25	$ 0.74
								$ -
201	Total Back-Office Revenue Assurance Analyst cost	Opex	Meters	$ 7.53	$ -	$ 0.35	$ 0.71	$ 14.41
202	Total cost of theft investigations	Opex	Meters	$ 5.11	$ -	$ -	$ 0.11	$ 11.14
203	Total CMS Deployment Center, Facility cost	Capex	Meters	$ 2.38	$ -	$ -	$ 0.78	$ 2.43
204	Total CMS Back Office & Clerical cost	Capex	Meters	$ 3.96	$ -	$ -	$ 1.29	$ 4.04
205	Total Service Representative Tools / Uniform cost	Capex	Meters	$ 0.26	$ -	$ -	$ 0.15	$ 0.18
206	Total Installed meter Quality Assurance / Quality Check cost	Capex	Meters	$ 0.89	$ -	$ -	$ 0.29	$ 0.91
207	Total CMS Deployment Coordination Labor cost	Capex	Meters	$ 1.29	$ -	$ -	$ 0.42	$ 1.31
208	CMS Field Installer Initial Training	Capex	Meters	$ 0.67	$ -	$ 0.39	$ 0.40	$ -
209	Total CMS Cellular Communication cost	Capex	Meters	$ 0.21	$ -	$ -	$ 0.07	$ 0.22
210	Handheld Devices cost	Capex	Meters	$ 0.00	$ -	$ -	$ 0.01	$ -
								$ -
300	Total AMI Additional Meter Data Services labor cost	Opex	Project Management	$ 5.61	$ -	$ -	$ 0.21	$ 11.37
301	Total AMI Additional Account Maintenance labor cost	Opex	Project Management	$ 2.81	$ -	$ -	$ 0.10	$ 5.69
302	Total System Testing management, internal resources	Capex	Project Management	$ 0.44	$ -	$ 0.38	$ 0.13	$ -
								$ -
400	Total Customer Engagement Program Design cost	Opex	Customer Engagement	$ 0.34	$ 0.19	$ 0.19	$ -	$ -
401	Total Customer Engagement Mass Media marketing cost	Opex	Customer Engagement	$ 2.27	$ -	$ 0.29	$ 0.58	$ 2.11
402	Total Town Hall / Workshop labor cost	Opex	Customer Engagement	$ 0.33	$ -	$ -	$ 0.09	$ 0.36
403	Total Town Hall / Workshop materials cost	Opex	Customer Engagement	$ 0.11	$ -	$ -	$ 0.03	$ 0.12
404	Total Content Development, Targeted Messaging cost	Opex	Customer Engagement	$ 9.22	$ -	$ 1.16	$ 2.36	$ 8.57
405	Total CSR Data Enhancement cost	Opex	Customer Engagement	$ 0.33	$ -	$ 0.38	$ -	$ -
406	Total Satisfaction Surveys cost	Opex	Customer Engagement	$ 4.75	$ -	$ 0.60	$ 1.22	$ 4.41
407	Total Sustainabililty Hub/ Demonstration set-up cost	Opex	Customer Engagement	$ 0.67	$ -	$ 0.76	$ -	$ -
408	Annual Sustainabililty Hub/ Demonstration hub rent cost	Opex	Customer Engagement	$ 0.65	$ -	$ 0.06	$ 0.06	$ 1.20
								$ -
501	CSS Enhancements Capex Cost	Capex	IT & Systems Integration	$ 5.40	$ 3.88	$ 2.01	$ -	$ -
502	Professional Services - Itron Solution Program Management cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
503	Energy Monitoring Portal Opex Cost	Opex	IT & Systems Integration	$ 2.70	$ -	$ 0.11	$ 0.00	$ 6.06
504	Green Button Connect Capex Cost	Capex	IT & Systems Integration	$ 1.97	$ -	$ 2.24	$ -	$ -
505	E-Commerce Marketplace Capex cost	Capex	IT & Systems Integration	$ 3.01	$ 0.67	$ -	$ -	$ 5.01
506	Customer Load Management Opex cost	Opex	IT & Systems Integration	$ 3.03	$ 0.27	$ 0.24	$ 0.25	$ 5.13
513	Telecom Capex cost	Capex	IT & Systems Integration	$ 1.05	$ 0.30	$ 0.27	$ 0.38	$ 0.29

Exhibit__(AMI-3)
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
II RATE CASE (ELECTRIC)							
514 ESB Capex cost	Capex	IT & Systems Integration	$ 5.40	$ 1.22	$ 1.99	$ 0.35	$ 4.98
516 Information Management Capex cost	Capex	IT & Systems Integration	$ 2.34	$ 1.00	$ 0.62	$ 0.40	$ 1.07
517 Data Lake Capex cost	Capex	IT & Systems Integration	$ 3.57	$ 0.26	$ 0.18	$ 0.25	$ 6.47
518 Professional Services - Itron Systems Implementation Workstream cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	-
519 SaaS Setup Fees - One Time Setup (Version upgrade and scale-up existing system) cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	-
520 SaaS Fees - Headend Software (OWOCCM, OWOC PM, IEE MDM, IoT FND, FDM) cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
521 Professional Services - System and Meter Firmware Upgrade cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
522 Telecom Opex cost	Opex	IT & Systems Integration	$ 0.27	$ 0.06	$ 0.06	$ 0.10	$ 0.10
523 Telecom RTB Cost	Opex	IT & Systems Integration	$ 10.09	$ -	$ 0.46	$ 0.71	$ 19.77
524 ESB Opex cost	Opex	IT & Systems Integration	$ 0.36	$ 0.15	$ 0.20	$ 0.06	$ -
525 ESB RTB Cost	Opex	IT & Systems Integration	$ 6.80	$ 0.08	$ 0.33	$ 0.59	$ 12.94
526 Data Lake Opex cost	Opex	IT & Systems Integration	$ 0.03	$ 0.04	$ -	$ -	$ -
527 Professional Services - Itron Solution Program Management Travel Expenses cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
528 Professional Services - Itron Systems Implementation Workstream Travel Expenses cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	-
529 Green Button Connect Opex Cost	Opex	IT & Systems Integration	$ 0.69	$ 0.13	$ 0.48	$ 0.19	$ -
530 Information Management Opex cost	Opex	IT & Systems Integration	$ 0.96	$ 0.04	$ 0.06	$ 0.06	$ 1.82
531 Information Management RTB Cost	Opex	IT & Systems Integration	$ 2.56	$ -	$ 0.16	$ 0.19	$ 4.92
532 Energy Monitoring Portal RTB Cost	Opex	IT & Systems Integration	$ 0.32	$ -	$ -	$ 0.03	$ 0.64
533 CSS Enhancements Opex Cost	Opex	IT & Systems Integration	$ 0.23	$ 0.17	$ 0.08	$ -	$ -
534 CSS Enhancements RTB Cost	Opex	IT & Systems Integration	$ 0.16	$ -	$ -	$ 0.02	$ 0.32
535 Green Button Connect RTB Cost	Opex	IT & Systems Integration	$ 3.87	$ -	$ -	$ 0.38	$ 7.74
536 Data Lake RTB cost	Opex	IT & Systems Integration	$ 1.09	$ -	$ 0.07	$ 0.10	$ 2.07
537 E-Commerce Marketplace Opex cost	Opex	IT & Systems Integration	$ 0.38	$ -	$ -	$ 0.11	$ 0.65
538 E-Commerce Marketplace RTB cost	Opex	IT & Systems Integration	$ 0.38	$ 0.03	$ 0.03	$ 0.03	$ 0.64
539 Customer Load Management RTB cost	Opex	IT & Systems Integration	$ -	$ -	$ -	$ -	$ -
							$ -
600 Cyber Security Project Capex Initial	Capex	IT & Systems Integration	$ 5.54	$ -	$ 3.71	$ 1.82	$ 1.04
601 Cyber Security Project Opex Initial	Opex	IT & Systems Integration	$ 2.18	$ -	$ 1.55	$ 0.73	$ 0.28
602 Cyber Security Project RTB O&M	Opex	IT & Systems Integration	$ 5.69	$ 0.00	$ 0.63	$ 0.48	$ 10.38
603 Cyber Security Refresh / Removal Capital	Capex	IT & Systems Integration	$ 5.72	$ -	$ -	$ -	$ 12.93
604 Cyber Security Capital Refresh / Removal Opex	Opex	IT & Systems Integration	$ 2.68	$ -	$ -	$ -	$ 5.87
Total Cost			**$ 466.99**	**$ 9.61**	**$ 28.24**	**$ 80.74**	**$ 638.86**
	Capex 100's - 400's		$247.52	$ -	$ 2.74	$ 63.82	$ 269.95
	Opex 100's - 400's		$54.22	$ 1.34	$ 5.79	$ 6.99	$ 79.36
	Total 100's - 400's		$301.75	$ 1.34	$ 8.53	$ 70.81	$ 349.31
	Capex 500's - 600's		$34.00	$ 7.33	$ 11.03	$ 3.20	$ 31.79
	Opex 500's - 600's		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total 500's - 600's		$165.24	$ 8.27	$ 19.72	$ 9.93	$ 289.56
	Total Capex		$281.52	$7.33	$13.76	$67.01	$301.73
	Total Opex		$185.47	$2.29	$14.48	$13.72	$337.13

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
	AMI RATE CASE (GAS)							
2	Total benefit from eliminated AMR meter readers	Opex	Avoided O&M	$ 11.66	$ -	$ -	$ -	$ 26.60
3	Total benefit from eliminated AMR meter reader vehicle costs	Opex	Avoided O&M	$ 0.74	$ -	$ -	$ -	$ 1.68
4	Total CO2 benefit from eliminated AMR reading vehicle emissions	Emissions	Net Avoided GHGs	$ 2.06	$ -	$ -	$ -	$ 4.58
5	Total benefit from reduction of meter investigations	Opex	Avoided O&M	$ -	$ -	$ -	$ -	$ -
6	Total benefit from remote metering capabilities	Opex	Avoided O&M	$ -	$ -	$ -	$ -	$ -
11	Total benefit from mitigation / reduction of damage claims	Opex	Avoided O&M	$ 2.88	$ -	$ -	$ -	$ 6.58
14	Total benefit from reduction of distribution losses (SM)	Opex	Avoided Distribution Losses	$ -	$ -	$ -	$ -	$ -
								$ -
16	Total fuel savings	Revenue	Avoided Energy	$ 6.39	$ -	$ -	$ 0.16	$ 13.58
17	Total CO2 savings from fuel savings, electric	Losses	Net Avoided GHGs	$ -	$ -	$ -	$ -	$ -
								$ -
18	Total CO2 benefit from reduction of meter investigations	Emissions	Net Avoided GHGs	$ -	$ -	$ -	$ -	$ -
19	Total CO2 benefit from remote metering capabilities	Emissions	Net Avoided GHGs	$ -	$ -	$ -	$ -	$ -
								$ -
26	Low-End Red. & Opt-In Total benefit from Critical Peak Pricing (CPP) peak shaving	Opex	Avoided Generation Capacity	$ -	$ -	$ -	$ -	$ -
27	Low-End Red. & Opt-In Total benefit from Avoided Energy due to Time-of-Use Program	Opex	Avoided Energy	$ -	$ -	$ -	$ -	$ -
28	Low-End Red. & Opt-In Total CO2 savings from Avoided Energy due to Time-of-Use Program	Emissions	Net Avoided GHGs	$ -	$ -	$ -	$ -	$ -
								$ -
100	Electric AMR Equipment Meter Replacement	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
101	Avoided AMI gas ERT / module equipment cost	Capex	Avoided AMR Capital	$ 30.26	$ -	$ -	$ 7.89	$ 32.84
102	Avoided AMI electric meter installation cost - Capex portion	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
103	Avoided AMI gas ERT / module installation cost - Capex portion	Capex	Avoided AMR Capital	$ 13.83	$ -	$ -	$ 3.32	$ 15.33
105	Avoided AMI demonstration period cost	Opex	Avoided AMR O&M	$ 0.28	$ -	$ 0.32	$ -	$ -
110	Avoided AMI network engineering, design, contracting cost	Capex	Avoided AMR Capital	$ 0.02	$ -	$ 0.03	$ -	$ -
111	Avoided Network communications equipment cost, Electric Meters	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
112	Avoided Network communications equipment cost, Gas Meters	Capex	Avoided AMR Capital	$ 0.30	$ -	$ -	$ 0.08	$ 0.32
113	Avoided Network communications installation cost, Electric Meters	Capex	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
114	Avoided Network communications installation cost, Gas Meters	Capex	Avoided AMR Capital	$ 0.02	$ -	$ -	$ 0.01	$ 0.03
115	Avoided Network communications LTE backhaul cost, Electric Meters	Opex	Avoided AMR O&M	$ -	$ -	$ -	$ -	$ -
116	Avoided Network communications LTE backhaul cost, Gas Meters	Opex	Avoided AMR O&M	$ 0.20	$ -	$ -	$ 0.00	$ 0.44
118	Avoided Network communications equipment cost upgrade	Capex	Avoided AMR Capital	$ 0.25	$ -	$ -	$ -	$ 0.48
121	Avoided Total AMI External Project Management labor cost - Capex portion	Capex	Avoided AMR Capital	$ 0.01	$ -	$ 0.01	$ 0.01	$ -
123	Avoided Total cost from call center and account payable volume, implementation	Opex	Avoided AMR O&M	$ 1.18	$ -	$ 0.07	$ 0.29	$ 1.21
124	Avoided Total AMI Internal Project Management Leadership Staff - Capex portion	Capex	Avoided AMR Capital	$ 0.47	$ -	$ 0.12	$ 0.12	$ 0.37
126	Avoided AMI electric meter installation cost - COR portion	COR	Avoided AMR Capital	$ -	$ -	$ -	$ -	$ -
127	Avoided AMI gas ERT / module installation cost - COR portion	COR	Avoided AMR Capital	$ 7.45	$ -	$ -	$ 1.79	$ 8.26
128	Avoided Total AMI External Project Management labor cost - Opex portion	Opex	Avoided AMR O&M	$ 0.04	$ 0.02	$ 0.02	$ 0.00	$ -
129	Avoided Total AMI Internal Project Management Leadership Staff - Opex portion	Opex	Avoided AMR O&M	$ 0.05	$ 0.06	$ -	$ -	$ -
131	Avoided AMI gas meter equipment cost	Capex	Avoided AMR Capital	$ 1.88	$ -	$ -	$ 2.29	$ -
132	Avoided AMI dual fuel with gas meter related installation cost - Capex portion	Capex	Avoided AMR Capital	$ 1.07	$ -	$ -	$ 1.31	$ -
133	Avoided AMI dual fuel with gas meter related installation cost - COR portion	COR	Avoided AMR Capital	$ 0.38	$ -	$ -	$ 0.46	$ -
134	Avoided AMI inventory equipment cost	Capex	Avoided AMR Capital	$ 0.71	$ -	$ -	$ 0.19	$ 0.77
								$ -
203	Avoided Total CMS Deployment Center, Facility cost	Capex	Avoided AMR Capital	$ 0.88	$ -	$ -	$ 0.29	$ 0.90

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
AMI RATE CASE (GAS)								
204	Avoided Total CMS Back Office & Clerical cost	Capex	Avoided AMR Capital	$ 1.47	$ -	$ -	$ 0.48	$ 1.50
205	Avoided Total Service Representative Tools / Uniform cost	Capex	Avoided AMR Capital	$ 0.10	$ -	$ -	$ 0.06	$ 0.07
206	Avoided Total Installed meter Quality Assurance / Quality Check cost	Capex	Avoided AMR Capital	$ 0.33	$ -	$ -	$ 0.11	$ 0.34
207	Avoided Total CMS Deployment Coordination Labor cost	Capex	Avoided AMR Capital	$ 0.48	$ -	$ -	$ 0.16	$ 0.49
208	Avoided CMS Field Installer Initial Training	Capex	Avoided AMR Capital	$ 0.25	$ -	$ 0.14	$ 0.15	$ -
209	Avoided Total CMS Cellular Communication cost	Capex	Avoided AMR Capital	$ 0.08	$ -	$ -	$ 0.03	$ 0.08
210	Avoided Handheld Devices cost	Capex	Avoided AMR Capital	$ 0.00	$ -	$ -	$ 0.00	$ -
								$ -
302	Avoided Total System Testing management, internal resources	Capex	Avoided AMR Capital	$ 0.02	$ -	$ 0.01	$ 0.00	$ -
								$ -
400	Avoided Total Customer Engagement Program Design cost	Opex	Avoided AMR O&M	$ 0.03	$ 0.02	$ 0.02	$ -	$ -
404	Avoided Total Content Development, Targeted Messaging cost	Opex	Avoided AMR O&M	$ 1.71	$ -	$ 0.21	$ 0.44	$ 1.59
								$ -
540	Avoided FCS Costs	Opex	Avoided AMR O&M	$ 1.33	$ 0.02	$ 0.04	$ 0.08	$ 2.56
								$ -
600	Avoided Cyber Security Project Capex Initial	Capex	Avoided AMR Capital	$ 0.51	$ -	$ 0.34	$ 0.17	$ 0.10
601	Avoided Cyber Security Project Opex Initial	Opex	Avoided AMR O&M	$ 0.20	$ -	$ 0.14	$ 0.07	$ 0.03
602	Avoided Cyber Security Project RTB O&M	Opex	Avoided AMR O&M	$ 0.53	$ 0.00	$ 0.06	$ 0.04	$ 0.96
603	Avoided Cyber Security Refresh / Removal Capital	Capex	Avoided AMR Capital	$ 0.53	$ -	$ -	$ -	$ 1.20
604	Avoided Cyber Security Capital Refresh / Removal Opex	Opex	Avoided AMR O&M	$ 0.25	$ -	$ -	$ -	$ 0.55
	Total Benefit			**$ 90.84**	**$ 0.11**	**$ 1.54**	**$ 19.99**	**$ 123.44**
								$ -
								$ -
100	AMI electric meter equipment cost	Capex	Meters	$ -	$ -	$ -	$ -	$ -
101	AMI gas ERT / module equipment cost	Capex	Meters	$ 30.26	$ -	$ -	$ 7.89	$ 32.84
102	AMI electric meter installation cost - Capex portion	Capex	Installation	$ -	$ -	$ -	$ -	$ -
103	AMI gas ERT / module installation cost - Capex portion	Capex	Installation	$ 13.83	$ -	$ -	$ 3.32	$ 15.33
104	AMI failed meter equipment replacement cost	Capex	Meters	$ -	$ -	$ -	$ -	$ -
105	AMI demonstration period cost	Opex	Meters	$ 0.37	$ -	$ 0.42	$ -	$ -
110	AMI network engineering, design, contracting cost	Capex	Communications	$ 0.02	$ -	$ 0.03	$ -	$ -
111	Network communications equipment cost, Electric Meters	Capex	Communications	$ -	$ -	$ -	$ -	$ -
112	Network communications equipment cost, Gas Meters	Capex	Communications	$ 1.48	$ -	$ -	$ 0.38	$ 1.60
113	Network communications installation cost, Electric Meters	Capex	Communications	$ -	$ -	$ -	$ -	$ -
114	Network communications installation cost, Gas Meters	Capex	Communications	$ 0.12	$ -	$ -	$ 0.03	$ 0.13
115	Network communications LTE backhaul cost, Electric Meters	Opex	Communications	$ -	$ -	$ -	$ -	$ -
116	Network communications LTE backhaul cost, Gas Meters	Opex	Communications	$ 1.01	$ -	$ -	$ 0.02	$ 2.20
117	AMI meter cellular service cost, Electric Meters	Opex	Communications	$ -	$ -	$ -	$ -	$ -
118	Network communications equipment cost upgrade	Capex	Communications	$ 1.24	$ -	$ -	$ -	$ 2.40
119	AMI communications failed equipment replacement cost	Capex	Communications	$ 0.17	$ -	$ -	$ -	$ 0.40
120	AMI communications equipment O&M cost (outside warranty)	Opex	Communications	$ 0.38	$ -	$ -	$ -	$ 0.83
121	Total AMI External Project Management labor cost - Capex portion	Capex	Project Management	$ 0.13	$ -	$ 0.09	$ 0.06	$ -
123	Total cost from call center and account payable volume, implementation	Opex	Back Office	$ 1.57	$ -	$ 0.09	$ 0.39	$ 1.61
124	Total AMI Internal Project Management Leadership Staff - Capex portion	Capex	Project Management	$ 0.47	$ -	$ 0.12	$ 0.12	$ 0.37
125	Total AMI Internal Project Management Business Support - Capex portion	Capex	Project Management	$ 0.32	$ -	$ 0.36	$ -	$ -

Exhibit__(AMI-3)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

	Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
AMI RATE CASE (GAS)								
126	AMI electric meter installation cost - COR portion	COR	Installation	$ -	$ -	$ -	$ -	$ -
127	AMI gas ERT / module installation cost - COR portion	COR	Installation	$ 7.45	$ -	$ -	$ 1.79	$ 8.26
128	Total AMI External Project Management labor cost - Opex portion	Opex	Project Management	$ 0.37	$ 0.16	$ 0.22	$ 0.03	$ -
129	Total AMI Internal Project Management Leadership Staff - Opex portion	Opex	Project Management	$ 0.05	$ 0.06	$ -	$ -	$ -
130	Total AMI Internal Project Management Business Support- Opex portion	Opex	Project Management	$ 0.19	$ 0.21	$ -	$ -	$ -
131	AMI gas meter equipment cost	Capex	Meters	$ 1.88	$ -	$ -	$ 2.29	$ -
132	AMI dual fuel with gas meter related installation cost - Capex portion	Capex	Installation	$ 1.07	$ -	$ -	$ 1.31	$ -
133	AMI dual fuel with gas meter related installation cost - COR portion	COR	Installation	$ 0.38	$ -	$ -	$ 0.46	$ -
134	AMI inventory equipment cost	Capex	Meters	$ 0.80	$ -	$ -	$ 0.21	$ 0.87
135	Professional Services - Field Deployment Support Workstream cost	Capex	Project Management	$ 1.93	$ -	$ 0.13	$ 0.61	$ 1.83
136	Professional Services - Field Deployment Support Workstream Travel Expenses cost	Opex	Project Management	$ 0.29	$ -	$ 0.02	$ 0.09	$ 0.27
								$ -
201	Total Back-Office Revenue Assurance Analyst cost	Opex	Meters	$ -	$ -	$ -	$ -	$ -
202	Total cost of theft investigations	Opex	Meters	$ -	$ -	$ -	$ -	$ -
203	Total CMS Deployment Center, Facility cost	Capex	Meters	$ 0.88	$ -	$ -	$ 0.29	$ 0.90
204	Total CMS Back Office & Clerical cost	Capex	Meters	$ 1.47	$ -	$ -	$ 0.48	$ 1.50
205	Total Service Representative Tools / Uniform cost	Capex	Meters	$ 0.10	$ -	$ -	$ 0.06	$ 0.07
206	Total Installed meter Quality Assurance / Quality Check cost	Capex	Meters	$ 0.33	$ -	$ -	$ 0.11	$ 0.34
207	Total CMS Deployment Coordination Labor cost	Capex	Meters	$ 0.48	$ -	$ -	$ 0.16	$ 0.49
208	CMS Field Installer Initial Training	Capex	Meters	$ 0.25	$ -	$ 0.14	$ 0.15	$ -
209	Total CMS Cellular Communication cost	Capex	Meters	$ 0.08	$ -	$ -	$ 0.03	$ 0.08
210	Handheld Devices cost	Capex	Meters	$ 0.00	$ -	$ -	$ 0.00	$ -
								$ -
300	Total AMI Additional Meter Data Services labor cost	Opex	Project Management	$ 2.08	$ -	$ -	$ 0.08	$ 4.23
301	Total AMI Additional Account Maintenance labor cost	Opex	Project Management	$ 1.04	$ -	$ -	$ 0.04	$ 2.11
302	Total System Testing management, internal resources	Capex	Project Management	$ 0.16	$ -	$ 0.14	$ 0.05	$ -
								$ -
400	Total Customer Engagement Program Design cost	Opex	Customer Engagement	$ 0.13	$ 0.07	$ 0.07	$ -	$ -
401	Total Customer Engagement Mass Media marketing cost	Opex	Customer Engagement	$ 0.84	$ -	$ 0.11	$ 0.22	$ 0.78
402	Total Town Hall / Workshop labor cost	Opex	Customer Engagement	$ 0.12	$ -	$ -	$ 0.03	$ 0.13
403	Total Town Hall / Workshop materials cost	Opex	Customer Engagement	$ 0.04	$ -	$ -	$ 0.01	$ 0.04
404	Total Content Development, Targeted Messaging cost	Opex	Customer Engagement	$ 3.43	$ -	$ 0.43	$ 0.88	$ 3.18
405	Total CSR Data Enhancement cost	Opex	Customer Engagement	$ 0.12	$ -	$ 0.14	$ -	$ -
406	Total Satisfaction Surveys cost	Opex	Customer Engagement	$ 1.76	$ -	$ 0.22	$ 0.45	$ 1.64
407	Total Sustainabililty Hub/ Demonstration set-up cost	Opex	Customer Engagement	$ 0.25	$ -	$ 0.28	$ -	$ -
408	Annual Sustainabililty Hub/ Demonstration hub rent cost	Opex	Customer Engagement	$ 0.24	$ -	$ 0.02	$ 0.02	$ 0.45
								$ -
501	CSS Enhancements Capex Cost	Capex	IT & Systems Integration	$ 2.01	$ 1.44	$ 0.75	$ -	$ -
502	Professional Services - Itron Solution Program Management cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
503	Energy Monitoring Portal Opex Cost	Opex	IT & Systems Integration	$ 1.00	$ -	$ 0.04	$ 0.00	$ 2.25
504	Green Button Connect Capex Cost	Capex	IT & Systems Integration	$ 0.73	$ -	$ 0.83	$ -	$ -
505	E-Commerce Marketplace Capex cost	Capex	IT & Systems Integration	$ 1.12	$ 0.25	$ -	$ -	$ 1.86
506	Customer Load Management Opex cost	Opex	IT & Systems Integration	$ 1.13	$ 0.10	$ 0.09	$ 0.09	$ 1.91
513	Telecom Capex cost	Capex	IT & Systems Integration	$ 0.39	$ 0.11	$ 0.10	$ 0.14	$ 0.11

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Niagara Mohawk Power Corporation d/b/a National Grid
AMI Costs and Benefits
(in millions)

Description	Type	Category 3 (Benefits) Category 2 (Costs)	NPV	FY 19	FY 20	FY 21	FY22-FY38
AMI RATE CASE (GAS)							
514 ESB Capex cost	Capex	IT & Systems Integration	$ 2.01	$ 0.45	$ 0.74	$ 0.13	$ 1.85
516 Information Management Capex cost	Capex	IT & Systems Integration	$ 0.87	$ 0.37	$ 0.23	$ 0.15	$ 0.40
517 Data Lake Capex cost	Capex	IT & Systems Integration	$ 1.33	$ 0.10	$ 0.07	$ 0.09	$ 2.40
518 Professional Services - Itron Systems Implementation Workstream cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted] -
519 SaaS Setup Fees - One Time Setup (Version upgrade and scale-up existing system) cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted] -
520 SaaS Fees - Headend Software (OWOCCM, OWOC PM, IEE MDM, IoT FND, FDM) cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
521 Professional Services - System and Meter Firmware Upgrade cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
522 Telecom Opex cost	Opex	IT & Systems Integration	$ 0.10	$ 0.02	$ 0.02	$ 0.04	$ 0.04
523 Telecom RTB Cost	Opex	IT & Systems Integration	$ 3.75	$ -	$ 0.17	$ 0.26	$ 7.34
524 ESB Opex cost	Opex	IT & Systems Integration	$ 0.13	$ 0.05	$ 0.08	$ 0.02	$ -
525 ESB RTB Cost	Opex	IT & Systems Integration	$ 2.53	$ 0.03	$ 0.12	$ 0.22	$ 4.81
526 Data Lake Opex cost	Opex	IT & Systems Integration	$ 0.01	$ 0.01	$ -	$ -	$ -
527 Professional Services - Itron Solution Program Management Travel Expenses cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
528 Professional Services - Itron Systems Implementation Workstream Travel Expenses cost	Opex	IT & Systems Integration	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
529 Green Button Connect Opex Cost	Opex	IT & Systems Integration	$ 0.26	$ 0.05	$ 0.18	$ 0.07	$ -
530 Information Management Opex cost	Opex	IT & Systems Integration	$ 0.36	$ 0.01	$ 0.02	$ 0.02	$ 0.68
531 Information Management RTB Cost	Opex	IT & Systems Integration	$ 0.95	$ -	$ 0.06	$ 0.07	$ 1.83
532 Energy Monitoring Portal RTB Cost	Opex	IT & Systems Integration	$ 0.12	$ -	$ -	$ 0.01	$ 0.24
533 CSS Enhancements Opex Cost	Opex	IT & Systems Integration	$ 0.08	$ 0.06	$ 0.03	$ -	$ -
534 CSS Enhancements RTB Cost	Opex	IT & Systems Integration	$ 0.06	$ -	$ -	$ 0.01	$ 0.12
535 Green Button Connect RTB Cost	Opex	IT & Systems Integration	$ 1.44	$ -	$ -	$ 0.14	$ 2.87
536 Data Lake RTB cost	Opex	IT & Systems Integration	$ 0.41	$ -	$ 0.02	$ 0.04	$ 0.77
537 E-Commerce Marketplace Opex cost	Opex	IT & Systems Integration	$ 0.14	$ -	$ -	$ 0.04	$ 0.24
538 E-Commerce Marketplace RTB cost	Opex	IT & Systems Integration	$ 0.14	$ 0.01	$ 0.01	$ 0.01	$ 0.24
539 Customer Load Management RTB cost	Opex	IT & Systems Integration	$ -	$ -	$ -	$ -	$ -
							$ -
600 Cyber Security Project Capex Initial	Capex	IT & Systems Integration	$ 2.06	$ -	$ 1.38	$ 0.68	$ 0.39
601 Cyber Security Project Opex Initial	Opex	IT & Systems Integration	$ 0.81	$ -	$ 0.58	$ 0.27	$ 0.11
602 Cyber Security Project RTB O&M	Opex	IT & Systems Integration	$ 2.11	$ 0.00	$ 0.23	$ 0.18	$ 3.86
603 Cyber Security Refresh / Removal Capital	Capex	IT & Systems Integration	$ 2.13	$ -	$ -	$ -	$ 4.81
604 Cyber Security Capital Refresh / Removal Opex	Opex	IT & Systems Integration	$ 0.99	$ -	$ -	$ -	$ 2.18
Total Cost			**$ 140.99**	**$ 3.57**	**$ 10.37**	**$ 25.75**	**$ 192.48**
	Capex 100's - 400's		$65.30	$ -	$ 1.02	$ 19.80	$ 67.41
	Opex 100's - 400's		$14.30	$ 0.50	$ 2.02	$ 2.27	$ 17.49
	Total 100's - 400's		$79.60	$ 0.50	$ 3.04	$ 22.06	$ 84.90
	Capex 500's - 600's		$12.63	$ 2.72	$ 4.10	$ 1.19	$ 11.81
	Opex 500's - 600's		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total 500's - 600's		$61.40	$ 3.07	$ 7.33	$ 3.69	$ 107.59
	Total Capex		$77.93	$2.72	$5.11	$20.98	$79.22
	Total Opex		$63.07	$0.85	$5.25	$4.77	$113.27

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Testimony of
Outdoor Lighting Panel

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Outdoor Lighting Panel

Dated: April 28, 2017

Direct Testimony of the Outdoor Lighting Panel

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I. Introduction and Qualifications

Q. Please introduce the members of the Outdoor Lighting Panel.

A. The Outdoor Lighting Panel (the "Panel") consists of Melanie W. Littlejohn, Pamela I. Echenique, and John E. Walter.

Q. Ms. Littlejohn, please state your name and business address.

A. My name is Melanie W. Littlejohn. My business address is 7496 Round Pond Road, North Syracuse, New York 13212.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. ("National Grid Service Company"), a subsidiary of National Grid USA ("National Grid"), as Vice President of Community and Customer Management for National Grid's New York operating companies, including Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or the "Company").

Q. Please describe your educational background and business experience.

A. I graduated from the State University of New York at Stony Brook in 1985, with a Bachelor of Arts in Liberal Arts. In 1997, I received a Master of Business Administration from Syracuse University. I joined National Grid in 1994, and have held several roles of increasing responsibility. Since 2005, I have been leading customer/stakeholder engagement for the Company. In October 2016, I assumed responsibility for the Outdoor Lighting organization.

Q. Have you previously testified before the New York State Public Service Commission ("Commission")?

A. No.

Q. Ms. Echenique, please state your name and business address.

A. My name is Pamela I. Echenique. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid Service Company as Director of New York Pricing. I am responsible for supervising the study, analysis, and design of delivery service rates, rate contracts, surcharge adjustment factors, riders, and terms and conditions of service for Niagara Mohawk, KeySpan Gas East Corporation d/b/a National Grid ("KEDLI"), and The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY").

Q. Please describe your educational background and professional experience.

A. My educational background and professional experience is set forth in Exhibit ___ (E-RDP-12) to the Electric Rate Design Panel's testimony.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission in the last two Niagara Mohawk electric rate cases (Cases 10-E-0050 ("2010 Electric Rate Case") and 12-E-0201

("2012 Rate Case") and in the last rate case for KEDLI and KEDNY (Cases 16-G-0058 and 16-G-0059).

Q. Mr. Walter, please state your name and business address.

A. My name is John E. Walter. My business address is 144 Kensington Avenue, Buffalo, New York 14214.

Q. By whom are you employed and in what capacity?

A. I am employed by Niagara Mohawk, and am the Manager of Outdoor Lighting – New York.

Q. Please describe your educational background and business experience.

A. I graduated from Clarkson College of Technology (now Clarkson University), in Potsdam, New York, with a Bachelor of Science in 1979 and a Master of Science in 1981; both degrees are in civil and environmental engineering. In 1996, I received a Master of Business Administration from the State University of New York at Buffalo. I am a registered professional engineer in the State of New York. From 1981 to 1983, I worked as a consulting engineering in Pittsburgh, Pennsylvania. I joined Niagara Mohawk in 1983. In 1990, I began working on Niagara Mohawk's outdoor lighting business, and I have held several roles of increasing responsibility overseeing aspects of the outdoor lighting business for Niagara Mohawk and National Grid. In 2016, I assumed my current role with Niagara Mohawk as Manager, Outdoor Lighting – NY.

Q. Have you previously testified before the Commission or any other regulatory commissions?

A. Yes. I provided testimony in four cases before the Commission related to the Company's outdoor lighting business, most recently in the Company's 2010 Electric Rate Case. Additionally, between 2009 and 2015, I provided testimony to the Massachusetts Department of Public Utilities, the Rhode Island Public Utilities Commission, and the New Hampshire Public Utilities Commission on behalf of National Grid companies.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of the Panel's testimony?

A. The Panel describes steps the Company is taking to improve the outdoor lighting service it provides customers, and changes it is proposing as part of this rate case to further improve that service and help meet the State's ambitious energy goals. Since the Company's 2012 Rate Case, advances in outdoor lighting technology, legislative initiatives, and increased interest from municipalities have spurred the Company to improve its service and identify ways to enable the transition to more advanced and efficient outdoor lighting equipment. With renewed focus on outdoor lighting and proposed improvements to the Company's outdoor lighting service tariff, P.S.C. No. 214 – Street, Highway, Roadway, and Other Outdoor Lighting (the "Lighting Tariff"), Niagara Mohawk will be well positioned to serve customers and meet the State's clean energy goals. Specific cost allocation and rate design proposals that support the proposed outdoor lighting improvements are addressed in the direct testimony of the Company's Electric Rate Design Panel.

Q. Please summarize the outdoor lighting improvements and changes described in this testimony.

A. To improve customer service and meet the State's energy goals, the Panel describes the steps the Company has taken to: (i) establish a new outdoor lighting department; (ii) initiate a street lighting asset audit; (iii) develop a secure portal to help the Company and customers better understand, document, and manage the outdoor lighting inventory (the "Outdoor Lighting Inventory Portal"); and (iv) enable conversions to light emitting diode ("LED") luminaires, including an opt-out approach for replacing existing high-intensity discharge ("HID") lights with more efficient LEDs.

The Panel also describes specific changes to the lighting business intended to support the aforementioned efforts, such as the establishment of a revenue decoupling mechanism ("RDM") and modifications to the depreciable life of outdoor lighting luminaires. In addition to these changes, the Panel explains two outdoor lighting pilot projects, one in the Town and Village of Colonie and the other in the City of Schenectady, that will help to evaluate additional approaches that may lead to improved outdoor lighting service offerings and provide greater value to customers.

The Panel also describes the Company's progress with new outdoor lighting asset sales procedures. Finally, the Panel outlines the following specific tariff-related changes: consolidating abbreviations in the definition section of the Lighting Tariff; providing a common definition of "material change" applicable to all service classifications ("SC"); phasing out legacy pricing exceptions, which will simplify service offerings, reduce pricing disparities, remove potential incentives to preserve obsolete technologies, and provide a more common baseline against which to evaluate LED conversion benefits; clarifying the circuitry allowance in SC-2 (Street Lighting, Unmetered, Company Owned, Company Maintained); and establishing a sunset date for SC-6 (Street Lighting, Unmetered, Customer Owned, Company Maintained). The cost and rate impacts of these proposals, as well as the specific tariff leaves incorporating the changes, are supported by the direct testimony and exhibits of the Electric Rate Design and Revenue Requirements Panels.

III. <u>Improving Customer Service</u>

Q. Please describe the Company's efforts to improve its service to outdoor lighting customers.

A. The Company has embraced the rapidly changing outdoor lighting landscape by pursuing a multi-faceted strategy to improve customer service. This strategy includes the creation of a new lighting department, initiation of an internal lighting audit, and the development of the Outdoor Lighting Inventory Portal. The Company's objective in pursuing this strategy is to enable it to efficiently respond to customer needs and overcome past shortcomings that stressed some customer relationships.

Q. Please describe the structure, staffing, and objectives of the new outdoor lighting department.

A. The Company's new outdoor lighting department consists of four full-time equivalent ("FTE") employees, three of whom are included in the Historic Test Year (the twelve months ended December 31, 2016), and one incremental FTE hired in January 2017. The costs associated with the incremental FTEs are shown in Exhibit ___ (RRP-3), Schedule 27. The new department is focused exclusively on the Upstate New York outdoor lighting business. Creation of this new department has heightened the focus on all aspects of outdoor lighting service within the Company and increased the level of senior management attention to the outdoor lighting business. This new department works with identified support from other functions within the Company, including billing, rates, legal, and regulatory, to effectively respond to customer LED conversion and outdoor lighting acquisition requests, billing and service issues, as well as manage outdoor lighting-related pilot/demonstration projects.

The department also participates in outdoor lighting industry groups, keeps abreast of advanced lighting and control technologies, and remains informed of best practices of other investor owned utilities. Establishment of the new outdoor lighting department is a clear demonstration of the Company's commitment to the outdoor lighting business and the customers it serves.

Q. Please describe the audit the Company is performing of its outdoor lighting inventory.

A. In response to recent customer billing inquiries questioning the accuracy of the Company's field inventory records, Niagara Mohawk initiated a comprehensive field inventory audit of the Company's billing and mapping records for its outdoor lighting facilities. The purpose of the audit is to investigate the accuracy of the in-service facility components providing outdoor lighting service to customers against their billing inventory and mapping records, reconcile any billing inaccuracies that may exist, and update and align the inventories of both record databases.

Q. What is the status of the audit?

A. In March 2017, the Company engaged Davey Resource Group to perform a system-wide inventory and billing record audit of the Company-owned/Company-maintained outdoor lighting infrastructure, which is covered by SC-2 of the Lighting Tariff. The audit will include a field audit of the Company's existing facilities, the results of which will be compared to the Company's existing outdoor lighting facility billing inventory records and the location-based mapping information in the Company's Geographic Information System ("GIS"). The Company expects Davey Resource Group to complete the fieldwork portion of the audit no later than December 31, 2017. Following the reconciliation of all database records, the Company anticipates sharing the results of the audit with Department of Public Service Staff.

Q. What will the Company do with the results of the audit?

A. The primary purpose of the audit is to identify inaccuracies in the Company's records, and upon receipt of the audit results, the Company will perform inventory reconciliation activities to identify and correct errors and inconsistencies in the database. However, the Company recognizes it has had challenges in the past in addressing customer concerns regarding outdoor lighting service. Therefore, in addition to correcting any specific errors the audit identifies, the Company also hopes to use the re-established database provided by the audit as an opportunity to address infrastructure, operations and maintenance strategies, as well as potential areas for process improvements in managing its outdoor lighting system data.

Q. Is the Company proposing any programs to enhance customers' access to outdoor lighting inventory and billing information?

A. Yes, the Company is proposing to implement a secure information portal – the Outdoor Lighting Inventory Portal – that will allow customers on-line access to view their outdoor lighting location-based facility information and also review their billing inventory records. Offering the Outdoor Lighting Inventory Portal will provide increased "self-service" opportunities for customers. The Company believes such functionality will reduce the number of billing accuracy questions and improve the timeliness of addressing such inquiries. An on-line secure information portal also could facilitate the replacement of the SC-2, Schedule SL2 reporting provision in the Lighting Tariff by providing customers with access to real-time billing inventory information.

Q. What is the cost for the new Outdoor Lighting Inventory Portal?

A. The Outdoor Lighting Inventory Portal is being implemented by National Grid Service Company, which is projecting capital investment costs of $0.500 million in the Rate Year (twelve months ending March 31, 2019) and $1.1 million in Data Year 1 (twelve months ending March 31, 2020). The costs to the Company associated with the Outdoor Lighting Inventory Portal will be reflected in the annual rent expense assessed by National Grid Service Company and presented in Exhibit __ (RRP-11), the Workpapers to Exhibit __ (RRP-3), Schedule 9, Workpapers 3, 6, and 9. Niagara Mohawk's rent expense forecast for this investment is $0.079 million and $0.359 million for its electric business in Data Year 1 and Data Year 2 (twelve months ending March 31, 2021), respectively.

IV. <u>Furthering Clean Energy Goals</u>

Q. Please describe the Company's efforts to support the State's clean energy goals with its outdoor lighting offerings.

A. The Company recently implemented an LED street light tariff provision for the conversion of existing HID roadway luminaires to more energy efficient LED technology. Municipal interest in the Company's offerings has been strong;

however, acceptance and authorization to proceed with conversions has been minimal. Some municipalities have expressed concern with the initial cost, relating largely to the required payment for the undepreciated investment of the existing luminaire assets to be removed. This also was noted in the recent order on Central Hudson Gas & Electric Corporation's ("Central Hudson") LED lighting petition (Case 16-E-0616), in which the Commission cited comments by Central Hudson and other parties that paying for the undepreciated book costs of existing HID luminaires to remove them was perceived as a "barrier to mass replacement of non-LED street lighting fixtures." The Commission nevertheless noted that "[i]mplementing LED street lighting can play a role in helping the State achieve its clean energy goals," and encouraged Central Hudson to consider energy efficiency measures to address this issue. In an effort to overcome this and other barriers, the Company proposes to implement an outdoor lighting energy-efficiency offering and several tariff-related changes aimed at helping to animate the LED conversion market.

A. <u>LED Tariff Offering</u>

Q. Please describe the LED conversion offering in the Lighting Tariff.

A. On May 23, 2016, the Commission approved the Company's LED tariff offering (Case 15-E-0645), which enables municipalities to initiate the conversion of existing in-service roadway street lighting luminaires from HID technology to LED technology. Under the LED portion of the Lighting Tariff, a customer converting from HID to LED facilities must commit to convert no less than 15 percent of the installed Company-owned roadway luminaires that serve the customer, or 100 units, whichever is greater. The customer also is required to pay a permanent discontinuance assessment for the HID facilities to be removed.

Q. How many roadway LED luminaires has the Company converted under its tariff offering?

A. Under the Lighting Tariff, the Company is obligated to replace HID luminaires with LED luminaires for up to 20 percent of its installed roadway luminaires in a given year. As of April 13, 2017, the Company has responded to 79 inquiries for information regarding the conversion of existing Company-owned HID roadway luminaires to LED luminaires. Of those, the Company has completed projects in eight municipalities, totaling 432 LED luminaires.

Q. How does the Company propose to increase the pace and scale of the LED conversions?

A. The Company proposes a few measures to advance the State's clean energy goals through increased installation and conversion of street lighting to LED technology. First, the Company intends to only offer LED luminaires for new street lighting service requests. Second, when it replaces failed HID roadway luminaires, it plans to use LED replacement luminaires. Finally, the Company proposes an energy-efficiency incentive program for street lighting conversions.

B. <u>New and Replacement Luminaires</u>

Q. Please explain the Company's proposed LED-only offering for new street lighting service requests?

A. The Company recently added several LED roadway luminaire standard offerings to the Lighting Tariff. The Company proposes to transition the HID roadway luminaire offerings to a closed status and to offer only the LED luminaire version for any new street lighting requests. As a result, all new street lighting installations will use LED technology.

Q. Is the Company proposing LED replacement luminaires for all of the other styles of HID luminaires (*i.e.*, non-roadway) that are presently in service?

A. The Company continues to evaluate the specifications and characteristics of LED luminaires that are considered replacements for all the various in-service, non-roadway HID luminaire styles and their associated lamp types and wattages. Based on its assessment, the Company will consider whether to make future tariff filings to expand the availability of LED replacements luminaires beyond the current roadway luminaire offerings.

Q. How does the Company propose to handle the replacement of failed in-service street lighting facilities?

A. The Company plans to manage routine maintenance matters, such as lamp or photocontrol replacements, in the same manner as it has in the past. That is, if an existing HID lamp, photocontrol, or starter fails, the Company will replace the failed component in-kind. However, if an HID luminaire fails and cannot be remedied by simple maintenance, the Company would replace the failed HID luminaire with an LED luminaire offering as designated in the Lighting Tariff. The replacement would be performed on an individual unit basis, with no incremental residual depreciation or removal cost to the customer.

Q. Please explain why this is in the public interest.

A. The adoption of LED lighting technology in outdoor applications provides superior lighting characteristics and quality in addition to being significantly more energy efficient. The enhanced safety, security, and visual performance from LED technology, in addition to the environmental and energy savings from such technology, provide substantial benefits to the public. Likewise, the Company's plan for on-going operation and maintenance of its outdoor lighting HID system will result in an efficient transition opportunity to convert to LED lighting without creating adverse financial impacts on municipal customers.

Q. How would the Company address municipalities that do not want to replace individual HID roadway luminaires with LEDs?

A. Municipalities who prefer not to participate in the LED replacement program will be able to opt out. To implement this opt-out option, the Company plans to defer the LED replacement plan until no earlier than April 1, 2019. This will allow sufficient time to conduct outreach with customers regarding the functional, physical, financial, and billing considerations of this approach, and allow customers an opportunity to determine if they want to opt-out.

Q. Why would a municipality elect to opt out from having LED replacements for failed HID luminaire facilities?

A. The different technologies in HID and LED lights produce differences in the light output (lumens) and the light color. These differences may create perceived non-uniformities that a municipality may not want. Rather than force a municipality to accept street lighting characteristics it considers undesirable, the Company proposes at this stage to allow municipal customers to exercise an opt-out choice. As experience with LED installations increases, the Company intends to revisit the continued viability of the opt-out option.

C. <u>Energy Efficiency</u>

Q. Please describe the Company's proposed energy-efficiency program to facilitate municipal LED conversions.

A. To help overcome barriers to adoption of LED street lighting and to enable municipalities to achieve important long-term cost savings and environmental goals, the Company proposes using incremental energy efficiency funds to support the conversion of existing HID roadway lighting to energy efficient LED technology. The Commission encouraged the development of such an initiative in its recent order on Central Hudson's LED street lighting program in Case 16-E-0616. The Company's energy-efficiency program would provide incentives to municipalities reflecting the net energy savings attributable to either customer-owned or Company-owned LED conversion projects. The Company estimates the annual cost of the program in the Rate Year and Data Years to be $1.6 million. Additional description of and support for the proposal is provided in the testimony of the Electric Customer Panel.

D. <u>Other LED Conversion-Related Lighting Program Changes</u>

Q. Is the Company proposing other program changes related to the implementation of LED outdoor lighting?

A. Yes. The Company is proposing to adopt an RDM applicable to outdoor lighting to remove any disincentive there might be to promote the installation of energy efficient LED lighting. The Company also proposes to modify the depreciable lives for the existing in-service street lighting luminaires to more accurately reflect actual operational experience. Finally, the Company proposes to implement a two-way LED capital investment tracker to credit customers if the Company is unable achieve its LED conversion targets, and remove any disincentive the Company might have to maximize potential HID to LED conversions.

Q. Please describe the Company's outdoor lighting RDM proposal.

A. The Company's proposed RDM is intended to remove any disincentive there might be to implement energy saving initiatives for outdoor lighting service, and would help support the conversion from the predominant HID technology to more advanced, energy-efficient LED technology. The RDM also would replace the deferral mechanism approved by the Commission in Case 15-E-0645. In that case, the Commission authorized deferrals to capture, among other things, unrecovered facility charges and lost energy-related revenues associated with HID to LED conversions. The Commission found that the Company "should be compensated for its loss of sales revenue for the [LED] conversions that are realized." Details of the RDM proposal, which is consistent with the Commission's finding, are supported by the testimony of the Electric Rate Design Panel.

Q. Please describe the Company's proposed changes to the depreciation lives of its outdoor lighting luminaires.

A. Currently, the Overhead and Underground Street Lighting Equipment accounts combine all associated outdoor lighting equipment, including luminaires, structures, circuit infrastructure and foundations. As a result, the current average service life used to define the plant accounting depreciation rate for overhead-sourced outdoor lighting HID luminaires is 50 years, and for underground-sourced outdoor lighting HID luminaires it is 70 years. These long average service life values equate to a low depreciation rate, generally contributing to a low facility offering price. However, this condition has also generally resulted in the reduced collection of depreciation expense through low street light facility rates, resulting in relatively high net book values of aged facilities even after years of service. The Company's position is that the current 50-year and 70-year service lives do not accurately reflect actual operational experience for luminaires. Further, these long service lives do not appear to reflect the general industry experience for such assets. Therefore, to align the depreciable lives for existing HID luminaires with industry norms and the Company's actual operating experience, Niagara Mohawk proposes to segregate luminaires from the balance of the street lighting plant accounts and to reduce the depreciable lives for all non-LED outdoor lighting luminaires to 20 years. The Company does not propose to change the existing -30 percent net salvage factor for the luminaires. In addition to better reflecting actual experience, the change in the existing luminaire (HID) service life also positions them closer to the 25-year assigned service life and -30 percent net salvage factor of LED outdoor lighting assets.

Q. Please describe how the Company determined the proposed 20-year average service life for existing luminaires.

A. The Company consulted with internal operations and engineering personnel, outdoor lighting manufacturers, and other investor owned utilities to determine a reasonable service life for HID luminaires. Factors considered in those discussions included the specific operating lives of various components that comprise the HID luminaire's operating system (*e.g.*, ballasts, capacitors, protection devices, *etc.*), environmental conditions (*e.g.*, ambient temperature, vibration, salt presence, *etc.*), and operating conditions (*e.g.*, day burning, relamping cycles, *etc.*). Based on those discussions and feedback, the Company determined that a reasonable HID luminaire useful life is about 20 years.

Q. What impact does modifying the average service life of HID luminaires and the associated depreciation expense rate have on outdoor lighting rates and on the net book value of existing facilities?

A. The change in the designated average service life and the associated depreciation expense rate for existing HID luminaires will have two primary effects. First, the change increases the collection of depreciation expense that is to be recovered in rates for the HID facilities. This would increase the rate for an HID luminaire asset compared to the rate based on a longer service life and corresponding lower depreciation rate. Second, the shorter service life has the effect of accelerating the reduction in net book value. As a result of segregating the street light accounts between luminaires and all other equipment, and using a 20-year life for luminaires versus 50-year life for the other equipment, a larger percentage of the book depreciation reserve will be allocated to luminaires. Thus, the remaining net book value of HID luminaires would be lower given a shorter service life than it would be with longer depreciable lives.

In addition to producing HID rates that are more reflective of the actual costs to provide service, the changes resulting from adopting shorter service lives for HID luminaires will make their rates more comparable to LED rates, and reduce their remaining net book value. The changes in HID luminaire service lives and the associated depreciation expense rate increase are reflected in the outdoor lighting rates presented by the Electric Rate Design Panel.

Q. Please explain how the Company proposes to account for the estimated LED conversions.

A. The Lighting Tariff provides that the Company's obligation to convert HID luminaires to LED in any annual period is up to 20 percent of the total installed roadway luminaires. Based on its experience to date, however, the Company does not expect to reach the 20 percent annual LED conversion level right away. Therefore, the Company's proposed capital plan includes capital investment for converting approximately 10 percent of HID luminaires in the Rate Year ($6.97 million, plus $0.775 million for cost of removal). The Company's proposed investment level takes into account the relatively slow pace of municipal conversions, as well as National Grid's commitment to manage rate impacts for customers.

The Company further estimates that HID to LED conversions will yield approximately $3.4 million in annual payments in the Rate Year and Data Years for the net book value of existing luminaires being converted. The Company based its estimate on recommendations in the depreciation study regarding the net book value of luminaires as of December 31, 2015, as supported by Exhibit ___ (KAK-2), Electric Statement C, to the testimony of Company Witness Dr. Kimbugwe A. Kateregga. The Company developed a system average net book value based on the number of luminaires as of December 31, 2015, and applied it to its annual estimate of 19,345 units to be retired. The calculation is presented in Exhibit __ (RRP-11), Workpaper for (RRP-7), Schedule 1, Workpaper 28.

Q. Please describe the LED capital investment tracker the Company is proposing.

A. The Company is proposing to establish a mechanism to track and reconcile capital investment amounts for municipal LED street light conversions. Although the LED conversion rate to date has been modest, the Company is proposing measures in this case filing to increase the number of such conversions. For example, the Company's proposed change in the depreciable lives of HID luminaires will result in greater convergence between LED and HID roadway luminaire facility rates, making LEDs comparatively more attractive. In addition, the LED street light energy efficiency program mentioned above and described in the direct testimony of the Electric Customer Panel is designed to reduce initial cost barriers to LED conversion for participating customers. The Company has not estimated the effects of these changes on the potential LED conversion rate; however, the Company expects that they will cause interest in conversions to increase significantly.

To enable the Company to effectively implement the conversion of up to 20 percent per year of its installed roadway luminaires without having to set higher initial rates, the Company proposes that rates be based on the 10 percent conversion level, and that a two-way tracker be established for costs incurred either in excess of, or below, the amount reflected in rates.

Q. How would the mechanism work?

A. The Company proposes to separately track its capital expenditures, including cost of removal, associated with municipal LED conversions. In the event that the annual amount incurred by the Company to convert LED roadway luminaires exceeds the amount reflected in rates ($7.745 million per year, which includes cost of removal), the Company will defer the revenue requirement for the amount in excess of the allowance in base rates. Conversely, to the extent the Company's costs to convert LED luminaires are lower than the rate allowance, the Company will credit a deferral for the revenue requirement impact of any under spend. In the event a multi-year settlement is reached that includes a tracker to reconcile LED costs with amounts reflected in rates, the Company proposes that such reconciliation be cumulative over the term of the multi-year agreement. For purposes of the tracker deferral, the revenue requirement will include a return on investment and associated depreciation as reflected in Exhibit __ (RRP-9), Schedule 2.

V. <u>Outdoor Lighting Pilot Projects</u>

Q. Is the Company participating in any outdoor lighting pilot or study projects?

A. Yes, the Company is participating in two pilot projects that will allow it to test and evaluate additional methods of furthering its renewed focus on customer service and clean-energy conversions. The first project involves the Lighting Research Center ("LRC") at Rensselaer Polytechnic Institute, the New York State Department of Transportation ("NYS DOT"), and the Village and Town of

Colonie, New York (the "Colonie Project"). The second project involves the City of Schenectady, New York (the "Schenectady Project").

A. <u>Colonie Project</u>

Q. Please describe the scope of the Colonie Project.

A. The Company has joined with the LRC, NYS DOT, and the Village and Town of Colonie to demonstrate and evaluate the application of LED roadway lighting technology as compared to HID technology. The project will focus on photometric performance and user acceptance of LED roadway lighting with regard to pedestrian and vehicular traffic safety in the Village and Town of Colonie. These parameters will be comparatively evaluated through engineered design analysis and public feedback. Analysis of the project will be further based on specific roadway lighting associated with existing HID technology and planned LED lighting technology provided by selected manufacturers.

Q. What is the Company's role with regard to the Colonie Project?

A. The Company is providing in-kind (field operation) services as part of the Colonie Project. These services reflect general field adjustments and/or modifications to approximately 151 street lights and associated infrastructure, as well as five or six new installations, to achieve the engineered lighting designs established for the designated test site. The Company estimates that the cost of these services will be no more than $36,000.

Q. Is the Company proposing to recover those costs?

A. The services will be similar in scope and type to what the Company generally provides municipalities in connection with outdoor lighting service. Accordingly, the Company is not proposing an incremental adjustment for the costs it incurs under the Colonie Project for incremental recovery.

B. Schenectady Project

Q. Please describe the Schenectady Project.

A. The Company has joined with the City of Schenectady on a 36 light pilot project that will utilize the Company's existing street lighting infrastructure as a platform for the consideration of advanced "smart" lighting technologies and the evaluation of potential benefits. This initiative plans for the conversion of existing HID outdoor lighting luminaires to LED and the deployment of ancillary wireless communication networks integrated into the LED lighting fixtures to enable smart device attachments. These attachments will allow for WiFi, live-video stream, and other reactive sensing applications that support operational controls or gather other analytic data. An example of the use of such technology is for the identification and communication of available parking spaces to the public through internet applications. Additionally, the connected lighting control devices will contain integrated circuit meter chip technology, which will be evaluated with respect to potential street light and ancillary device metering capabilities.

Q. How does the Schenectady Project differ from the LED conversions authorized in the Lighting Tariff?

A. In the Schenectady Project, the HID luminaires will be replaced for a temporary period (two years) by the pilot project LEDs. The LEDs will be owned by the City, while the Company will retain ownership of the removed HID luminaire facilities. The Company will work with the City to install the new luminaires and associated device attachments, benefitting from the information gathered during the project term regarding the functionality of the various device attachments and metering technology.

Q. What do the City and the Company hope to learn from the Schenectady Project?

A. There are a number of different technologies on the market today beyond standard operating controls for LED luminaires, which include more sophisticated devices that allow for remote dimming, WiFi capabilities, environmental monitoring, security cameras and even applications such as parking space monitoring. The products being considered for the Schenectady Project represent this type of high-end technology and the project will help promote informed choices to be made by the Company, the City of Schenectady, and other municipalities looking at how best to upgrade their outdoor lighting technology.

Q. Are there any costs associated with the Schenectady Project?

A. The Company will provide labor and transportation for the purpose of removing and installing the demonstration project luminaires and device attachments.

Q. Is the Company proposing to recover those costs?

A. Similar to the Colonie Project, the services to be provided in connection with the Schenectady Project will be similar in scope and type to what the Company generally provides municipalities in connection with outdoor lighting service. Accordingly, the Company is not proposing an incremental adjustment for the costs it incurs under the Schenectady Project for incremental recovery.

Q. Is the Company considering any other outdoor lighting projects with the City of Schenectady?

A. The Company is separately working with the City of Schenectady to develop a REV "Smart City" demonstration project that would involve a larger population of outdoor lights and a variety of network communication and device technologies. The "Smart City" demonstration project is described in more detail in the direct testimony of the Electric Customer Panel.

VI. Asset Sales

Q. Please describe the Company's efforts to facilitate outdoor lighting asset sales to municipalities in accordance with Public Service Law § 70-a.

A. Purchasing outdoor lighting assets is another option for municipalities seeking to achieve long-term cost savings and environmental goals. To standardize the process regarding such sales, the State enacted a new street light asset sale law, which the Commission effectuated in its *Order Approving Tariff Amendments with Modifications* issued October 14, 2016 in Case 15-E-0745, *et al*. The Company, consistent with the Commission's order, amended the Lighting Tariff to establish a standardized process for the sale of street lighting assets to municipalities. As of April 10, 2017, the Company has received 21 customer inquiries regarding the purchase price of street lighting systems within those municipalities. At present, three customers have indicated their intent to move forward to procure the street lighting infrastructure.

VII. General Lighting Tariff Changes

Q. Is the Company proposing additional changes to the Lighting Tariff?

A. Yes, the Company is proposing changes to the definitions section of the Lighting Tariff, phasing out legacy pricing exceptions, and some additional changes to specific service classifications.

A. Definitions

Q. Please explain the Company's changes to the definitions section of the Lighting Tariff.

A. The Company proposes two changes to the definitions section: (i) consolidating the abbreviations; and (ii) providing a new definition of "material change" that would be applicable to all service classifications.

Q. Please explain the Company's proposal to consolidate abbreviations.

A. The Lighting Tariff includes a number of abbreviations for certain terms included throughout the Lighting Tariff and, most predominantly, in SC-2, Schedule SL2. Here, the Company proposes, as in the Company's P.S.C. 220 – Electricity Tariff ("Electric Tariff"), to group the abbreviations in a common location.

Q. Please explain the Company's proposal to develop a common definition of "material change" for use across all outdoor lighting service classifications.

A. The Lighting Tariff does not include a common definition of "material change," even though the term is made generally applicable to all service classifications and specifically referenced in SC-4 and SC-6. The lack of clarity creates inconsistencies and confusion among customers. Therefore, the Company proposes to clarify in the Lighting Tariff that a material change means "any addition, retirement, installation, removal, replacement, relocation, and/or reconfiguration of a single equipment component, assembly, device or other element and/or the aggregate of equipment components that comprise an assembly or installation at a designated location." The proposed definition changes are presented in revised Lighting Tariff leaves.

B. <u>Legacy Pricing Exceptions</u>

Q. What are outdoor lighting pricing exceptions?

A. The Company provides service for standard lighting facilities at rates set forth in the Lighting Tariff. In some circumstances, customers pay non-standard rates for service to lighting facility configurations that pre-date the Lighting Tariff. Such non-standard arrangements, known as pricing exceptions, have been carried forward in SC-2 of the Lighting Tariff. The pricing exceptions are fixed annual facility charges that apply to specific facility combinations. Pricing exceptions represent a discount from standard outdoor lighting service rates, and apply to the specific indicated facility combination so long as it remains in place.

Q. How are pricing exceptions presented in the Lighting Tariff?

A. In the Lighting Tariff, SC-2, Table 22, the Company lists pricing exceptions by service location, number of units, specific combination of facilities that comprise the given pricing exception, and the associated annual facility charge. As of April 1, 2015, there were 13 different customers receiving pricing exceptions, with 27 different facility combinations, taking service on more than 10,000 pricing exception units. Some customers have as few as four pricing exception units, while other customers have hundreds or thousands.

Q. Please explain the Company's proposal to phase out legacy pricing exceptions.

A. The Company proposes to phase out the existing pricing exceptions over five years, beginning with the Rate Year. The Company prefers this approach, as it provides affected customers adequate time to prepare for the pricing change. The Electric Rate Design Panel describes the revenue neutral manner in which the Company proposes to implement this proposal.

Q. Why is the Company proposing to phase out pricing exceptions?

A. Eliminating the pricing exceptions will result in similarly situated customers being treated similarly for comparable service, enable the Company to provide more uniformity and standardization in the service it provides, simplify customer billing, and improve operation and maintenance activities. Further, because pricing exceptions are tied to maintaining particular legacy asset configurations, they can perpetuate the existence of non-standard, aged equipment in the field. It also will establish a consistent baseline for customers to evaluate the relative benefits of advanced technology (*e.g.*, LED) options. As mentioned above, and as described in more detail in the testimony of the Electric Rate Design Panel, the phase out is intended to be revenue neutral such that the increase in revenues from the phase out is credited against the revenue requirement of non-pricing exception or standard service.

Q. Does the Company propose any other changes to the Lighting Tariff with respect to SC-2 pricing exceptions?

A. Yes, in the way of a clarification. The pricing exception provision in the Lighting Tariff makes clear that the applicability of pricing discounts is "specific to facility combinations established prior to the effective date of this [Lighting] Tariff." Lighting Tariff, SC-2 (E) Obsolete Facility Charges, (7) Pricing Exception Charge. As customers modify facility combinations subject to a pricing exception or the Company replaces a pricing-exception facility because it has reached the end of its useful life, the Company's practice is to remove the particular facility combination from the individual pricing exception list in the Lighting Tariff. In the interest of avoiding potential disagreements regarding continued pricing exception eligibility in cases where a facility combination changes, the Company proposes to clarify the Lighting Tariff. This additional language will make clear that any modification or replacement to a facility combination subject to a pricing exception will result in the elimination of the pricing exception for that facility combination going forward. Again, by removing legacy pricing exceptions, the Company believes it will establish a common baseline for evaluating the benefit of LED conversions and eliminate the incentive to preserve inefficient technology in the field.

C. <u>Service Classification Changes</u>

Q. What change is the Company proposing to make to Rate Schedule SC-2?

A. In the 2012 Rate Case, the Commission approved the Company's proposed restructuring of the underground circuitry allowance established in SC-2, Table 9. The Company phased in the new rate structure over a three-year period, with all customers who receive underground service and, separately, those receiving underground residential service, charged the same rates, respectively, regardless of the circuitry used or when and how it was installed. Although the Company implemented the new rates, its final tariff compliance filing inadvertently failed to include additional changes to the circuitry allowance. As a result, the tariff includes circuitry rates for underground service and underground residential service, but it does not reflect the proper circuitry allowance that formed the basis upon which those rates were established. Here, the Company seeks to correct the Lighting Tariff to reflect the 150-foot circuitry allowance, and to clarify that any excess footage would be billed through Rule 28 of the Electric Tariff. This proposed change is supported by the Electric Rate Design Panel.

Q. What change is the Company proposing to make to Rate Schedule SC-6?

A. The Company is proposing to sunset SC-6 as of March 31, 2021, at which point, absent alternative arrangements, customers would be transferred to SC-3 (energy only) service.

Q. Why is the Company proposing this change?

A. With only nine customers having a total of ten bill accounts comprising a total of 400 lamp facilities and the rapidly evolving lighting technology, the Company believes it is no longer economic for it to provide maintenance service to a minimal number of customer-owned lights. Therefore, the Company proposes to terminate the provision of service under SC-6 as of March 31, 2021. This deferred termination of the service will enable SC-6 customers to obtain alternative means of maintenance, or prepare for the transition to a new service classification provided by the Company. The Company intends to implement an outreach plan to all affected customers advising them that after March 31, 2021, any SC-6 lighting facilities for which the customer has not arranged alternative maintenance service will automatically transition to SC-3 service.

VIII. Conclusion

Q. Does this conclude your testimony?

A. Yes.