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July 2, 2009

Hon. Jaclyn A. Brillling  
Secretary  
New York State Public Service Commission  
Empire State Plaza  
Agency Building 3  
Albany, NY 12223-1350

Re: Case 09-E-0310 - In the Matter of American  
Recovery and Reinvestment Act of 2009 - Utility  
Filings for New York Economic Stimulus,  
Central Hudson Gas & Electric

Dear Secretary Brillling:

In response to Mr. Michael Corso's letter dated June 29, 2009 regarding the American Recovery and Reinvestment Act of 2009 (ARRA) for applications to the U.S. Department of Energy (DOE) under the Electricity Delivery and Energy Reliability (EDER) program, Central Hudson Gas and Electric Corporation (Central Hudson) submits its revised list of proposed projects including supporting detail.

Central Hudson has continued to refine its project list from the original filing made on April 17, 2009. These refinements are the result of ongoing discussions with Staff, collaborative efforts amongst the New York State Transmission Owners and the NYISO, as well as modifications made to the DOE EDER Funding Opportunity Announcements (FOA). The projects that Central Hudson has proposed all would seek to apply for funding under the Smart Grid Investment Grant Program (SGIG). For the projects that are being submitted as part of this filing additional refinements continue to be made so that they are responsive to the goals and evaluation criteria defined in the FOA. As the project information is revised we will provide timely updates to Staff.

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Central Hudson has removed several of the infrastructure related projects included in its earlier filing. While these projects may have included elements of Smart Grid we feel that are not a good fit under the goals set forth in the final FOA. If Staff feels that these projects should continue to be pursued we would be open to those discussions.

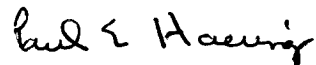
Included in this filing is an updated project list, project details and justifications, environmental assessment form and copies of the interrogatory responses pertaining to the stimulus projects that have been filed to date.

Information included in this filing details cost estimates, cyber security, and vendor specific information for our Smart Grid project. The negotiation of terms for services of a Smart Grid vendor will have a direct impact on the bills of all Central Hudson customers. As a result, this confidential information has been redacted from this filing and an unredacted version has been filed with the Records Access Officer.

Central Hudson continues to work collaboratively with the New York State Transmission Owners, NYISO, NYSERDA and New York Smart Grid Consortium on these and other potential projects.

If there are any questions related to this filing please do not hesitate to contact me directly

Respectfully submitted,



Paul E. Haering

Enclosure

cc: Mr. Michael Corso - via email  
Ms. Kimberly Harriman - via email  
Mr. Michael Worden - via email

## ATTACHMENT A

Re: CHG&E Smart Grid Initiative - An Investment Program Project

Central Hudson Gas & Electric (CHG&E) plans to submit an application to DOE under the Smart Grid Investment Grant DE-FOA-0000058 in the award size category of Small Project and topic area of Integrated and/or Crosscutting Systems.

CHG&E has reviewed the FOA document issued on June 25, 2009 and is prepared to submit the required Letter of Intent according to the Phase 1 deadline of July 16, 2009 and the proceeding application on or before August 6, 2009.

The attached document "Central Hudson Gas & Electric Smart Grid Initiative: An Investment Program Project" is representative of the information that will be provided to DOE. Section 1 is attached to this filing, while sections 2 through 6 are to be combined in to the overall Project Plan, as identified on pg. 19 in the above referenced Funding Opportunity Announcement. The six sections defined by DOE and the corresponding CHG&E proposal sections are:

- 1) Project Abstract - Attachment I
- 2) Tasks & Project Schedule - Pages 33-34 (Schedule and Deployment)
- 3) Management Plan - Pages 36-37 (Management Team, Project Risks and Mitigation Plan), Attachment II
- 4) Methodologies, Strategies, and Processes for enabling Smart Grid - Pages 7-24 (Enabling the Smart Grid, Smart Grid Investment Program Plan)
- 5) Interoperability & Cyber Security - Pages 25-32 (Interoperability & Cyber Security)
- 6) Data Collection and Evaluation Plan and Cost-Benefit Analysis - Pages 34-35 (Systems Evaluation), Pages 38-40 (Cost Benefit)

Please note that the data contained in pages 25-32 (Interoperability & Cyber Security), 41 (Table 10) of the Central Hudson Gas & Electric Smart Grid Initiative document have been submitted in confidence and contain trade secrets or proprietary information, and such data shall be used or disclosed only for evaluation purposes.

While the attached CHG&E project proposal fulfills the general DOE application requirements, there are some sections that will be edited for the final DOE application. The "Communication Technology Comparison" section was added strictly for clarification purposes for the Commission and will be removed from the final application document. Other areas will be edited for content in order to meet the 40 page maximum Project Plan length requirement as stated in the FOA. Due to the compressed timeframe between the Commission filing deadline and the release of the FOA, the following sections are under review and will require further development and inclusion of specific details in order to meet all of the criteria outlined by DOE in the DE-FOA-0000058 document. Therefore, developments of the following sections in the CHG&E document are still in progress:

Project Planning, Progress, and Evaluation -  
specifically pertaining to the management plan  
Cost Benefit - specifically pertaining to the  
"Expected Benefits" within Table 9

CHG&E will submit any changes to the Smart Grid Initiative document to the Commission prior to submitting the Investment Grant application to DOE.



Central Hudson Gas &  
Electric Smart Grid Initiative:  
An Investment Program Project

July 2, 2009

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# Central Hudson Gas & Electric Smart Grid Initiative: An Investment Program Project

July 2, 2009

## Executive Summary

Central Hudson Gas & Electric Corp. (CHG&E) wishes to pursue funding for the company's Smart Grid Initiative through the American Recovery and Reinvestment Act Investment Grant funding opportunity at a fifty percent match.

CHG&E believes that not only does the company's Smart Grid program meet the goals set forth by organizations such as DOE, FERC, NARUC, NIST, and the NYSPSC, but also exceeds these goals in pursuit of a truly intelligent grid.

The CHG&E Initiative involves the deployment of a two-tiered RF Mesh Advanced Metering Infrastructure (AMI). The communication infrastructure incorporates a meter level mesh for "smart" gas and electric meters and a distribution automation layer mesh for distribution communication and control. The distribution layer mesh data will be considered higher priority when transmitting to aid the workforce in shorter response times. The distribution layer data will be fed in to two systems, CHG&E's existing OMS system as well as yet to be incorporated modeling software capable of real-time data evaluation for system planning, operation, and dispatching assistance. In order to wield the influx of newly available meter data a Meter Data Management System (MDMS) will be implemented. Beyond the meter and in to the customer's home, Home Area Networks (HAN) will be installed on a volunteer basis and dynamic customer rate offerings will be offered to the same subset volunteers. On the substation level, advanced relaying and control schemes will be developed for the integration of distributed resources. Along the same lines of promoting clean energy, charging stations for plug-in hybrid electric vehicles will be installed at various locations. All of the systems mentioned were chosen not only for the capabilities of the technology but also for the ease of integration and interoperation as well as for their open architecture and the scalability of the systems for the inclusion of future Smart Grid applications. Overall, the combination of technologies will create ten (10) intelligent circuits from source to end-user.

Success of the Smart Grid project is also contingent on consumer reaction. If customers are not committed to shifting their usage or changing energy consumption patterns then goals for peak load shifting and load curtailment cannot be achieved. Therefore CHG&E will be dedicating a significant effort toward consumer education and outreach programs involving creation of a Smart Grid hotline, mailings and surveys, public forums with sample equipment set-ups, focus groups, and the development of a customer web portal where consumers can view their usage, learn about new rates and energy saving techniques, and get their questions answered.

CHG&E sees this investment as not only a means for saving in O&M costs through work efficiency improvements but as a huge leap towards achieving the high expectations of customers related to reliability, energy efficiency, and environmental responsibility. Customer's look to CHG&E to forge the path and create a more stable and robust grid. Smart Grid measures are necessary to achieve this vision.

The project plan consists of a two-year deployment with an additional two years of system integration, data collection and evaluation, and consumer behavior study. CHG&E realizes that to date many of the technologies included in the plan have not been proven in mass markets therefore they must be tested and compared to competitors' technologies before consideration for full deployment beyond the scope of this initiative. In addition, customer reaction cannot be measured without having a baseline of usage history for comparison purposes. Collecting this data not only will aid CHG&E in its evaluation effort but also will allow customers to see the impact they can make through their own efforts and how that effort can literally "pay off" in their utility bill.

The CHG&E Smart Grid initiative encompasses all aspects of the grid from the source to the consumer. Like many successful business plans the road to success involves all of the stakeholders making sure that each knows their role and how it impacts the overall goal. Smart Grid can be viewed in the same fashion. Sporadic improvements will extend the life of the grid in the short term; however, widespread changes and improvements in technology, operations, and maintenance are necessary for sustainability. CHG&E proposes a project that engages all stakeholders encouraging a collaborative effort between the utility, customers, and regulators to create a more intelligent grid that will exceed the needs and expectations of everyone involved in the process.

### **Commission Orders**

This document describes a proposal of a Smart Grid Investment Program Project at Central Hudson Gas & Electric Corp. (CHG&E).

As part of the approved Joint Proposal for Cases 05-E-0934 & 05-G-0935, CHG&E agreed to conduct an evaluation of an Automated Meter Reading (AMR) system and put forward its "Automated Meter Reading (AMR) Pilot Proposal" (dated December 28, 2006) for approval. Separately, the Public Service Commission (Commission) issued "Order Relating to Electric and Gas Metering Services<sup>1</sup>," issued and effective August 1, 2007, directing CHG&E to study AMI.

A "Notice Seeking Comment" followed on October 10, 2007, requesting comments from all Utilities pertaining to the Commission's Advanced Metering Initiative, which CHGE responded on December 10, 2007.

An "Order Rejecting Filing and Requiring New Filing," issued and effective December 19, 2007, rejected CHG&E's AMR Pilot Proposal and required CHG&E to submit a new AMI proposal. Following a "Notice of AMI Technical Conference" sent on March 3, 2008 an AMI Technical Conference was held on April 14 and 15, 2008.

On February 13, 2009, the Commission issued the "Order Adopting Minimum Functional Requirements for Advanced Metering Infrastructure Systems and Initiating an Inquiry Into Benefit-Cost Methodologies", Case 09-M-0074. The order identified twelve separate requirements of the proposed pilot programs that must be met by either, the vendor and technology chosen, or by CHG&E.

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<sup>1</sup> Related to Cases 94-E-0952, 00-E-0165, and 02-M-0514.

CHG&E filed its AMI proposal on April 14, 2009 and three days later filed its AMI/Smart Grid proposal. This document builds upon the April 17<sup>th</sup> filing providing a much more detailed description of the Smart Grid project as well as itemized costs and information pertaining to the intention to seek fifty percent funding through the Department of Energy (DOE) American Recovery and Reinvestment Act (ARRA) Smart Grid Investment Grant Program DE-FOA-0000058.

### **Smart Grid Investment Program Overview**

Based on the Energy Independence and Security Act of 2007 and the recently issued "Report to NIST on the Smart Grid Interoperability Standards Roadmap" developed by EPRI, CHG&E defines its Smart Grid project as a coordinated effort to create a two-way information and communication platform from the substation through the distribution system to the end user. The effort will enable real-time data capture, reporting, communication and control creating opportunities to decrease system losses, peak shave, defer infrastructure reinforcements, improve power quality, and react more effectively to system disturbances.

CHG&E views the Smart Grid technologies as an opportunity to modernize, optimize, and improve the overall efficiency and operation of the grid. Smart Grid technologies also introduce an opportunity to improve customer relations by offering a means for customers to educate themselves and be educated by utilities in terms of the manner in which they consume energy and ways that they can alter their usage patterns to their advantage and ultimately decrease their energy bill.

CHG&E wishes to be explicitly clear that this investment program project is not solely a technology test to validate the suitability of the selected technologies for system deployment throughout CHG&E's territory. Therefore CHG&E ensures that the initiative will be focused on its purposes to quantify the added benefits of Smart Grid technologies to both the grid as well as to consumers. The system must be scalable, adaptable, and vendor agnostic.

CHG&E will also include technologies capable of integrating with older technologies in order to limit cost of new infrastructure, exploit existing proven systems, and promote interoperability between systems. Through the implementation of such equipment CHG&E aims to satisfy the Smart Grid criteria of limiting stranded investment, which will benefit both CHG&E and the consumer in the long run.

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## **Smart Grid Investment Program Goals**

The CHG&E Investment Program Project will demonstrate the following Smart Grid applications and characteristics:

1. Reduction of energy demand through customer programs including dynamic rate offerings, application of load control appliances and energy usage displays, and customer web access to usage information and energy saving techniques.
  - ❑ Combined installation of “smart” meters and Home Area Network (HAN) devices such as usage displays, “smart” thermostats, and “smart” appliance control devices.
  - ❑ Offer customer access to web portal displaying individual usage profiles and history as well as the ability to view customer billing impacts by choosing the dynamic rate offerings based on prior usage history.
  - ❑ Offer customers the tools to make more informed energy usage decisions
2. Integration of data systems and software tools through the adoption of a Meter Data Management System (MDMS) and near real-time load flow data analysis tool.
  - ❑ The MDMS will integrate with the existing legacy Customer Information System (CIS) as well as the Outage Management System (OMS)
  - ❑ The MDMS will provide real time data from endpoints on the grid to the load flow program for circuit modeling and engineering, operation, and planning analysis functions
  - ❑ The analysis tool will be used to perform load flow scenarios as well as provide both engineering and system operations with timely and accurate simulation capabilities for improved operation of the electric system
3. Circuit modernization and optimization through the instantaneous communications with electronic reclosers, automatic switched capacitor banks, automatic load transfer switches, and voltage and current monitoring equipment.
  - ❑ Reduce losses through improved voltage and VAR control
  - ❑ Available data to determine load balancing needs
  - ❑ Improved reliability through real-time and more precise outage and fault location detection and restoration information
4. Substation modernization through the installation of advanced protective relaying equipment
  - ❑ Development and deployment of adaptive settings and control schemes
  - ❑ Creation of full circuit communications and control network from the source transformer to the end of the circuit to improve voltage profiles and facilitate voltage reduction efforts
5. Provisioning for Distributed Resources
  - ❑ Improved control and protection schemes
  - ❑ Monitoring of power quality and voltage profiles
  - ❑ Installation of plug-in hybrid electric vehicle (PHEV) charging stations

6. Determine compatibility with existing systems and technologies to determine level of future investment
  - ❑ Evaluate the feasibility of retrofitting existing equipment, such as voltage regulators, with sensing and communication modules vs. replacement with newer technology
7. Integration of Natural Gas System Monitoring
  - ❑ Deploying communication modules in existing electronic monitoring systems of regulator stations for real-time data capture, leveraging use of the communication platform.
8. Evaluation of technology and data validation
  - ❑ Deployment in service territory areas specifically chosen to represent the economically and geographically diverse customer segments of CHG&E's territory.
9. Realize and quantify the benefits to CHG&E's electric system and its customers as well as the possibility of attracting new customers to the system
  - ❑ Quantify customer interest and involvement in Smart Grid technologies and energy consumption reduction and reallocation programs
  - ❑ Evaluate information from "smart" meters in MDMS and compare to historic load models to determine future implications
  - ❑ Enrollment in Dynamic Rate and HAN programs, and customer behavior therein.

### **Smart Grid Criteria**

CHG&E shares in the goals and visions of the Department of Energy (DOE), the New York State Public Service Commission (Commission), the Federal Energy Regulatory Commission (FERC), National Association of Regulatory Utility Commissioners (NARUC), and the National Institute of Standards and Technology (NIST). CHG&E proposes a Smart Grid Initiative project that will meet the following criteria as outlined by the agencies previously mentioned:

#### **Department of Energy Smart Grid Functions – As defined EISA, Section 1306(d)**

- ❑ Ability to develop, store, send and receive digital information concerning electricity use, costs, price, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system, through one or a combination of devices and technologies.
- ❑ Ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device.
- ❑ Ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize or report that information by digital means.

- ❑ Ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations.
- ❑ Ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices.
- ❑ Ability of any appliance or machine to respond to such signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention.
- ❑ Ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual.

#### Energy Independence and Security Act (EISA) of 2007 - Section 1306

- ❑ Transmission and distribution equipment fitted with monitoring and communications devices to enable Smart Grid functions.
- ❑ Metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system that are capable of Smart Grid functions.
- ❑ The purchase and install costs of software that enables devices or computers to engage in Smart Grid functions

#### Energy Independence and Security Act (EISA) of 2007 - Section 1301

- ❑ Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid
- ❑ Development and incorporation of demand response, demand-side resources, and energy efficiency resources
- ❑ Deployment of 'smart' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communication concerning grid operations and status, and distribution automation
- ❑ Integration of "smart" appliances and consumer devices
- ❑ Provision to consumers of timely information and control options
- ❑ Lowering barriers to adoption of Smart Grid technology, practices, and services

#### FERC/NARUC Smart Grid Collaborative

- ❑ Minimizes stranded cost risk by providing for upgradeability
- ❑ Will maintain grid reliability
- ❑ Addresses data integrity
- ❑ Addresses user authentication

- ❑ Protects against unauthorized use and logs modifications or changes made
- ❑ Addresses how physical security will be maintained
- ❑ Portfolio of projects has scale sufficient to draw statistically valid conclusions regarding consumer impact, grid impact, and technology
- ❑ Physical and cyber-security is tested
- ❑ Reduction in energy demand or consumption will be documented
- ❑ Documentation is shared with public while protecting customer privacy
- ❑ Documentation of types of customer-specific data will be collected
- ❑ Plan for protecting customer privacy
- ❑ Documented process for securing customer permission to collect private data
- ❑ Plan on surveying customer receptivity to the project

### **Enabling the Smart Grid**

Smart Grid and Automated Metering Infrastructure (AMI) technology are touted in the utility industry as revolutionary. The Smart Grid combines distinct metering hardware components and electric distribution devices such as communication modules, current and voltage sensors, and remotely operated equipment meshed with highly advanced software and communication platforms. Together they produce meter and distribution system data at varying rates of speed depending on architecture, which is stored, manipulated and can be transformed into applicable information for multiple end users in hierarchical fashion dependent on the end user.

The architecture of the Smart Grid system is not succinct, given the advancement curve of current technology, and multiplicity of components. The system interacts with almost every business and operational process of utility delivery service, and must be interfaced and integrated in a usable form. Data alone is not sufficient as information is really what is needed for effectiveness.

In the broadest sense, the Smart Grid is generally comprised of eight components as follows:

1. Utility systems
2. Meter Data Management System (MDMS)
3. Data collection
4. Wide Area Network (WAN)
5. Local Area Network (LAN)
6. Metering Hardware / Software
7. Home Area Network (HAN)
8. Distribution Automation

Each of these interlocking levels is further evaluated below:

1. Utility System

Within the utility, Smart Grid data must interface with a number of current systems and software applications, from legacy CIS and billing systems to more current OMS and GIS applications. Each of the systems will require much of the same, but also different information meaning that the raw data needs to be analyzed and “routed” appropriately at the required level of clarity and at designated intervals.

2. MDMS – Meter Data Management System

The MDMS is the storeroom for raw meter data, and provides a repository for points to be pushed into or pulled from other information systems. This head end system needs to be based on open standards and protocols, diverse and scalable, and able to handle almost boundless amounts of data.

3. Data Collection

The flow of data needs to be determined, as well as what pieces of data are actually required. The movement of data over the communication network brings forth concerns in regard to cost and data security, as with other components. Most systems currently available today hinge on being IP addressable.

4. WAN – Wide Area Network

Communication from the meter data collector back to the data repository is varied, and technology is emergent. Backhaul can be accomplished through fiber optic, radio frequency, cellular, or cable television communications. Required speed and volume of data acquisition generally determines this component. WAN selection should be based on area availability and the various means of communication that the utility currently uses.

5. LAN – Local Area Network

Similar to the methods mentioned for WAN, communication between meters to the data collection agent can be accomplished through radio frequency via direct sequence spread spectrum (DSSS), frequency hopping spread spectrum (FHSS), cellular, or broadband over power line (BPL). All are discussed in detail in the “Technology Comparison” section. The LAN is different for each vendor and preference should be given to the technology that best meets the service territory needs based on meter density and geographic challenges that may cause interruptions to the communication system.

While some latency is acceptable for regular meter reads in most cases, the resolution of the question for bandwidth necessary for other applications and speed for automated distribution equipment applications, where protective devices are involved, is of importance.

6. Metering Hardware

Most solid-state meters available on the market are adapted for remote reading through the addition of a chipset that resides under the glass. Gas meters will require the installation of a communications module. Each meter communicates to a backhaul point, which typically consolidates information and sends it over the WAN. Technology also exists that can communicate directly from the meter to the MDMS. Scalability at this level is a concern as is backward compatibility.

7. HAN – Home Area Network

Communication at the home, with the customer is widely diverse. Not only the technology by which it is accomplished, but also with the level of interaction desired. In many cases, the existing market barrier for the HAN is not getting the information (not data) to the customer, but how the customer reacts.

Communication to the customer can be accomplished to virtually any interface, whether it is an in-home display, thermostat, a cellular phone, or Internet web page. Communication can be originated and information disseminated from several sources including the meter itself, the MDMS, or other utility systems. Communication pathways can be wireless, hardwired following home electrical pathways, or broad spectrum via the Internet. Each of these avenues provides degrees of complicity with information volume, ease of use, and security.

Consumer behavior modification is key to demand response or load shifting efforts. Creative rate structures need to be assessed, applied, and measured in order to quantify the secondary benefits necessary to justify a business case for system-wide deployment.

8. Distribution Automation

Distribution automation is the operation of the electric distribution system in real-time utilizing equipment with communication and remote control capabilities. Equipment can either work autonomously or through a software platform where operators have supervisory access. In doing so, the distribution system can be operated in a more efficient manner resulting in decreased system losses. In addition, reducing the system peaks can decrease the stress on equipment prolonging the life span and lessen the need for infrastructure reinforcements.

Overall, interoperability between all of the Smart Grid systems is key. The system must be scalable, adaptable, and is best suited to be technology and vendor agnostic.

## **Smart Grid Investment Program Plan**

The Project will consist of the following characteristics:

- ❑ Installation of approximately 13,500 “smart” endpoints, inclusive of electric and gas meters, approximately 2000 Home Area Networks, electric distribution automation and monitoring as well as gas monitoring equipment.
- ❑ Integration and installation of a Meter Data Management System (MDMS) in-house and operated by CHG&E personnel. The MDMS will interface with CIS, OMS, GIS, and other internal systems.
- ❑ Installation of electric distribution equipment with real-time monitoring, communication and control capabilities. The equipment will include: substation relays, electronic reclosers, switched capacitor banks, sensors and communication modules to be applied to voltage regulators to collect voltage, current and power quality data.
- ❑ Installation of communication modules in electronic monitoring equipment on the natural gas system.
- ❑ Dynamic rate offerings.

### **Location**

CHG&E has selected multiple areas within the service territory for the deployment of the Smart Grid technologies. The areas chosen incorporate a diverse customer pool including residential, commercial and industrial customers, as well as are representative of the challenging topography within the CHG&E territory including densely treed areas, mountainous, or sparsely populated regions.

Altogether, CHG&E has selected areas that encompass approximately two percent of its total customers and approximately five percent of its electric distribution circuits within its territory. This selection size is large enough to extrapolate the effects of full deployment yet small enough to minimize the effects of an underperforming technology.

The first area selected is served by the Knapps Corners Substation (Figure 1). Knapps Corners is located at the junction of Spring Road and Kerr Road in Dutchess County. It is close to NYS Route 9, a busy road running through Poughkeepsie and Fishkill. The area encompasses a portion of the Town of Poughkeepsie, which is fairly densely populated. The area is viewed as being typical of suburban mixed residential/commercial types of land use that are expanding in the CHG&E territory as a result of population influx from the urban areas to the South.

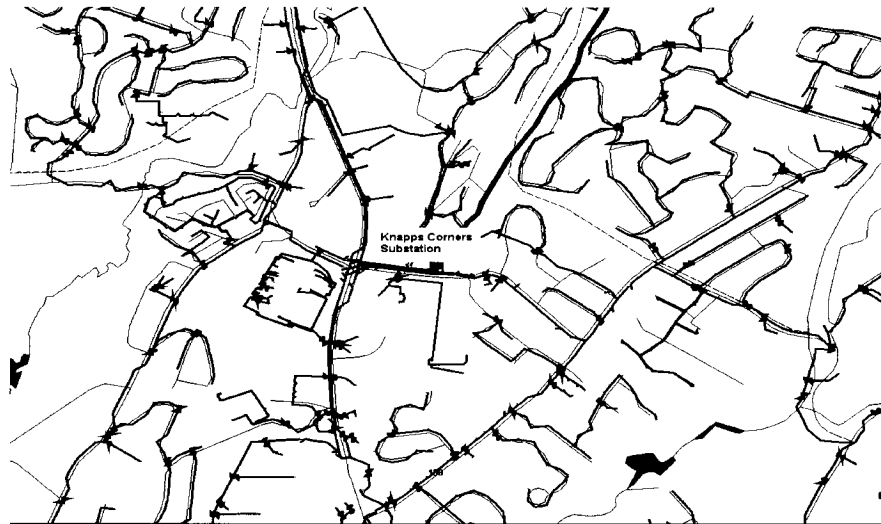


Figure 1: Knapps Corners Substation Circuit Diagram

The second area is Saugerties Substation (Figure 2), which is located in the Village of Saugerties in Northern Ulster County. It is composed of a mix of suburban as well as rural electric and gas customers. The terrain will offer a true test to the integrity of the mesh communications system. The installation of Smart Grid equipment such as electronic reclosers and monitoring equipment will offer much needed upgrades to the existing circuit as well as improve reliability in an area where many areas are difficult to access and often result in extended response time.

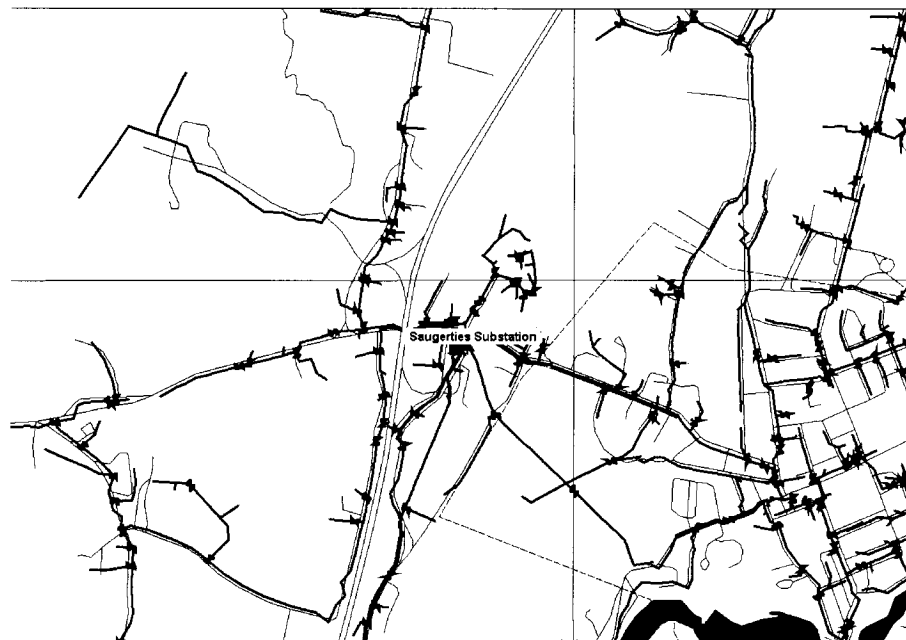


Figure 2: Saugerties Substation Circuit Diagram

The third area is the Modena Substation (Figure 3) located in the Town of Plattekill in Southern Ulster County. The area was selected due to its large concentration of Photovoltaic customer installations. These distributed generation installations will provide an opportunity to test the net metering capabilities of the system as well as monitor the affects that distributed resources have on the distribution system.



Figure 3: Modena Substation Circuit Diagram

### Schedule

Deployment of the project consists of six (6) key components, as follows:

1. Process planning, education, outreach and training
2. Installation of distribution equipment, communication modules and meters
3. Establish communications infrastructure
4. Install, integrate, and validate Distribution system analysis software
5. Install, integrate, and validate Meter Data Management System
6. Receive approval and implement dynamic rates

These components are further broken down and described in the project schedule and cost flow projection within the Smart Grid Investment Program Timeline section.

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### Technology & Vendor Selection

As specified in the Commission order dated February 13, 2009 Appendix 1, the following minimum requirements of the AMI system must be met:

1. AMI systems must be compliant with all applicable ANSI standards, Commission regulations and Federal standards, such as FCC regulations.
2. AMI systems must provide net metering.
3. AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with the auxiliary device if it is the only means of a visual read of consumption data.
4. AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.
5. AMI meters must have sufficient on-board meter memory capability to ensure meter data is not lost in the event of an AMI system failure and that the previous and current billing period of billing data is stored on the meter.
6. AMI systems must have the ability to provide customers direct, real-time access to electric meter data. The data access must be provided in an open non-proprietary format.
7. AMI systems must have the ability to remotely read meters on-demand.
8. At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.
9. AMI systems must have two-way communications capability, including ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.
10. AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network (HAN) to provide direct or customer-activated load control.
11. AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.
12. AMI systems must have the following security capabilities:
  - i. Identification – uniquely identify all authorized users of the system to support individual accountability
  - ii. Authentication – authenticate all users prior to initially allowing access
  - iii. Access Control – assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated
  - iv. Integrity – prevent unauthorized modification of data, and provide detection and notification of unauthorized actions
  - v. Confidentiality – secure data stored, processed and transmitted by the system from unauthorized entities

- vi. Non-repudiation – provide proof of transmission or reception of a communication between entities
- vii. Availability – ensure that information stored, processed and transmitted by the system is available and accessible when required
- viii. Audit – provide an audit log for investigating any security-related event
- ix. Security Administration – provide tools for managing all of the above tasks by a designated security administrator

CHG&E will ensure that the selected Vendor will meet or exceed all of the above-mentioned criteria.

#### Vendor Selection Criteria

Vendor selection is to be determined based on but not limited to the following criteria:

- ❑ Reliability, accuracy, and stability of technology and equipment used
- ❑ Feasibility of technology and equipment to be utilized in CHG&E service territory
- ❑ Cost
- ❑ Compatibility with current systems (OMS, CIS, GIS, etc.)
- ❑ Opportunities for expansion of the program in to full deployment as well as future advanced Smart Grid projects
- ❑ Security features (both hardware and cyber)

Any system deployed will require extensive IT support for collecting and managing data and information in an effective, secure manner.

Compliance with local, state, and federal codes and standards must be followed inclusive of entities such as FERC, NIST, the FCC, etc. Major concerns exist over not only the security of data, but also the security of the grid itself as control technology is embedded within the system.

#### Communication Technology Comparison

There are many different Smart Grid technologies and vendors on the market today. CHG&E has contacted and communicated with each of the following vendors (in alphabetical order): Aclara, Aeris, CellNet Hunt, Current, Elster, Itron, Landis & Gyr, Sensus, Siemens/Emeter, Silver Spring, Smart Synch, and Trilliant. Below is an overview of the different Smart Grid technologies that were reviewed and the associated advantages/disadvantages of the technologies:

Broadband Power Line (BPL) Technology: Broadband Power Line (BPL) communications is the two-way sending and receiving of broadband communications signals over the utility's power lines. Speeds of up to 10 megabits/second (Mbps) can be achieved via this technology. Couplers need to be installed at every distribution transformer on the utility's primary distribution system to either bridge the communications signal around the transformer or inject the signal through the transformer onto the secondary. Power line communications devices at the couplers

communicate to backhaul points on the primary. From there, the backhaul points communicate back to the office via mainly fiber optics.

BPL systems are not limited in bandwidth in the way that mesh networks are. BPL can reach up to 10 Mbps speed; however, lower than 1 Mbps is thought to be needed to accomplish most Smart Grid applications. Therefore, the large bandwidth that can be achieved using a BPL system would not be utilized currently by the utility. But the BPL system would be susceptible to signal disruption by any noise occurring on the distribution system.

Cost is also higher for the initial installation of a BPL system than for a radio frequency (RF) mesh system or wireless system. Deployment could cost anywhere from 25% to 40% more than an RF or wireless deployment. In addition, the required infrastructure could prove cumbersome to maintain due to the vulnerability to damage during storm events.

Radio Frequency (RF) Mesh Technology: RF Mesh technology utilizes radio frequency two-way communications to send and receive signals from meters or other points on the system to backhaul points. From these backhaul points, communications to the head end are accomplished via cellular, fiber optic, cable television, telephone, a second level higher frequency mesh, or possibly WiMax communications.

Usually in an RF mesh, the meters and other devices automatically choose the best path of communications to the backhaul point. The meters and other devices communicate with each other and “hop” signals from one to another until reaching the backhaul point. If one backhaul point fails, the smart meters and devices will recalibrate to find a new backhaul point to communicate through.

The ability of the RF Mesh to recalibrate and select its best path is a major advantage it has over a BPL system. Since many of CHG&E distribution lines are radial, a BPL system would only be able to choose one path to communicate back to its own backhaul point and back to the office. If that path were not functional in the BPL system, there would be no means of communication.

Another major benefit of the RF Mesh is that it is truly metering technology and requires minimal pole-mounted infrastructure, while still having the ability to provide advanced communication for activities related to grid operations and analysis. Installation work will consist of predominantly meter change-outs. Some pole top backhaul points will need to be installed. However, with some RF Mesh technologies in good cellular coverage areas, meter points can act as the backhaul point and no pole top transmitters need to be installed.

The drawback to any RF or wireless technology is the concern about security. All major vendors are aware of this and have gone to the extent of even hiring hackers to try to break into their mesh security systems. With any IP addressable system, security is a concern, but many systems using IP data transfer schemes are successfully employed by utilities today. Most companies use encryption methods to address security concerns such as those defined by AES-128.

Line of sight and interference can be a problem when deploying an RF system. The ability of the smart meter to recalibrate and find its best path helps alleviate some of these concerns.

Many Vendors are currently working with distribution equipment manufacturers to develop Smart Grid devices and applications that can be utilized with an RF Mesh

system. Automatic operation of distribution switched capacitor banks and automatic load transfer switches have been tested and are operating successfully at various utilities using RF Mesh technologies. Most vendors have sensing equipment but limited equipment is available commercially. Most are only offering 'pilot' or test equipment.

**900 MHz RF Mesh:** Operation in the 900 MHz band can offer greater range (i.e., operation over greater distances) than a 2.4 GHz system. Also, 900 MHz communications use greater power to propagate the signal.

These 900 MHz systems operate at anywhere from 40 kilobits/second (Kbps) to 100 kbps. AMI today already requires 10 Kbps. Therefore, 900 MHz systems allow limited room for growth for future Smart Grid and other applications.

**2.4 GHz RF Mesh:** Up to 10 hops can be used over a 2 to 3 mile range to communicate back to the backhaul points. Repeaters can be used in various locations to boost the RF signal hops to the backhaul points. Approximately 100,000 endpoints (i.e., electric meters, gas meters, distribution automation sensors, programmable thermostats, and in-home displays) can communicate back to one backhaul point.

The 2.4 GHz RF Mesh system allows operation over a wider frequency spectrum than a 900 MHz system. This larger spectrum allows the system to sidestep interference by constantly scanning more available channels to communicate through.

The 2.4 GHz system supports data rates of 250 Kbps compared to the maximum of 100 Kbps speeds of a 900 MHz system. This faster data rate provides more scalability for future Smart Grid applications.

Additionally, several technologies including WiFi, Bluetooth, unlicensed WiMax, and ZigBee for home automation have standardized on the 2.4 GHz spectrum for communications. This standardization and interoperability may provide economies of scale that may drive down costs for 2.4 GHz deployments.

Even though a 900 MHz system can provide greater range, the 2.4 GHz system relies more on the availability to make smaller "hops" over shorter distances using its wider spectrum to operate. The 2.4 GHz system therefore does not need to communicate over long distances, but can do so if there is line of sight.

Another benefit to the 2.4GHz system is that 5.8GHz RF WAN is available as a backhaul option. This higher frequency WAN provides higher speed and lower latency emulating a wired system without the added infrastructure burden.

Cellular Communications: CHG&E also has evaluated cellular communications. The use of the public wireless system may bring down the costs for the Smart Grid deployment since an existing system is being used. There is an opportunity in some areas for cellular communications to act as a "gap-filler" where other communications are not available.

Cellular coverage may still be sparse in many rural areas in the CHG&E service territory and may not work in all areas of CHG&E's service territory. Also, once again, for any wireless communications security of the system may be an issue as well as any associated risk with using non-utility owned infrastructure.

Based on the information above CHG&E has chosen the RF Mesh system with a 2.4 GHz meter level mesh and a 5.8 GHz distribution equipment level mesh for its Smart Grid communications platform solution. CHG&E has explored the use of public networks for providing the data backhaul pathway, however, the utility's chosen network

technology while having the ability to utilize existing infrastructure does not require it. The communications platform has the ability to travel wirelessly via a second level of RF, thus eliminating a data conversion and infrastructure link.

### Smart Grid Investment Program Technology Applications

#### a. Advanced Metering Infrastructure (AMI)

AMI in terms of Smart Grid is not just a means for remote meter reading. The mesh technology that CHG&E will employ will act as the communication backbone for the Smart Grid initiative. The technology chosen will operate on two different mesh levels. The first, lower priority, level is the metering data. The second, higher priority, level will encompass the electric distribution equipment applications. This data will be transferred at a faster speed with higher bandwidth capabilities to, for example, OMS and the analysis tool for outage reporting and fault location determination.

AMI is also an enabling technology. CHG&E intends to use it not only for communication of data but also as the facilitator for demand response programs. The AMI technology provides the necessary data to bill customers according to dynamic rate offerings, to provide customers with real-time solutions to their queries through CSR access to their meter data at the time of the call, to allow customers to sign up for demand response and to provide a means to decrease load during peak conditions. AMI will be the connection between the customer, the HAN equipment, and CHG&E.

Without AMI, many of the programs CHG&E wishes to offer its customers would not be available.

In addition, each “smart” meter can be considered a monitoring point on the distribution system. Real-time data can be collected in terms of voltage and current at each meter location. This data availability will aid in speeding power quality issue resolution and eliminate the need to install specialized power quality monitoring equipment as well as for transformer load management.

#### b. Home Area Network Installations

CHG&E will utilize the Home Area Networks (HANs) to gauge customer response to their electric usage by several techniques. Each technique will require customer approval to install equipment into homes and businesses at no charge to the customer.

CHG&E will conduct and study multiple control groups. Using combinations of installed devices such as wall displays that will communicate electric meter data in an easy to read format and thermostats or other control devices installed on appliances such as water heaters or pool pumps to aid in demand response. The customer groups will be broken down according to Table 1.

	Group 1	Group 2	Group 3	Group 4
Number of Customers	500	500	500	500
In Home Display		X		X
'Smart' Thermostat			X	X
Load Control Device			X	X
Web Access	X	X	X	X

Table 1

Group 1: Control Group

Customers within this group would have their meter replaced with a smart meter and have access to the customer web portal where they can view their usage. Customers would be educated on how to access their information on the web page and be assigned a unique sign on and password.

Group 2: Display Group

Building upon the Control Group, the Display Group will have access to the customer web portal but will also be provided with an in-home usage display. Customers would be educated on how to use the display in addition to instruction on the customer web portal.

Group 3: Demand Response Group

Unlike the Display Group, the Demand Response Group would not receive an in-home usage display but they would have access to the web page and also receive a 'smart' thermostat and load control device for use with a hot water heater, pool pump, or other similar appliance. This group would be able to control the thermostat and control device through the web and the usage data collected from the "smart" meter will allow CHG&E to study customer demand response.

Group 4: All Access Group

The All Access Group will receive all of the devices available, the in-home usage display, the 'smart' thermostat and load control device, as well as access to the web portal. This group will aid in determining just how much information is necessary for customers to make informed decisions about their energy usage.

By creating HANs, CHG&E will be able to explore the possibility of creating new services to provide to customers. CHG&E will study the customer response to HANs by conducting surveys and focus group activities as well as tracking changes in usage patterns.

In order to fully evaluate the effects of HAN equipment, a baseline of the customer's usage will have to be established. Since the meter deployment will occur well before the Meter Data Management System and Customer Web Portal are fully integrated, the time between meter deployment and full system integration will be used to gather data and create a baseline for each customer. The meter data from these customer groups will also be compared to the data collected from the remaining "smart" meters that are not involved in the HAN program.

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Dynamic rates will be offered to these customer control groups as described below in "Customer Programs" (Part "g").

c. Meter Data Management System (MDMS)

The advent of the AMI meter poses an opportunity for the utility to collect usage information no longer just on a cumulative kWh scale but in terms of predetermined intervals such as hourly, fifteen minute, etc. But along with the data availability comes the challenge of storing and disseminating the data in to useful information. The current Customer Information Systems and billing systems are not designed to handle either the quantity of data that will be available nor the rules to validate the data. Therefore a system must be brought in to perform this data management function and an MDMS is the answer.

The MDMS is the epicenter of the data collection, storage, and dissemination. It will integrate with recently adopted systems such as the data analysis tool, OMS, and GIS as well as legacy systems such as CIS. It will provide platforms for data validation and evaluation by all work groups within CHG&E well beyond just those involved with customer billing.

The MDMS can house the information related to every meter within our service territory, not just the newly installed AMI meters. Therefore it can be relied upon as an asset management tool in addition to meter usage data storage. The system also performs validating, editing and estimating functions that would eliminate approximately 70% of the manual work related to error processing, prorating and rebilling efforts within the current process. Applications may also be added to the MDMS for MV-90 and other metering systems so that it eventually can replace these systems all together and simplifying the meter management process.

The MDMS provides access to the data collected by the electric distribution equipment and can perform transformer load calculations based on the data collected by the "smart" meters. It can alert users to missing read data, facilitate remote read requests, and perform data validation tests. Complex billing calculations are also a function within and MDMS, which can then be supplied to a CIS system.

Working in tandem with the home area networks and the "smart" meters, the MDMS will provide a web-based portal where customers can log on using a unique user defined login ID and password to view their usage information. Graphical displays as well as spreadsheet representations of their interval usage data can be viewed for the day prior as well as past history starting from when the "smart" meter was installed. It is anticipated that customers will also have the capability to view what their bill would have been for previous months on varying rates offered by CHG&E through a "Rate Estimator Calculator" application. It is intended that customers could even utilize the "Carbon Footprint Calculator" to determine how their energy usage is affecting the environment.

This information makes for a more well-informed and knowledgeable consumer. It is the objective of CHG&E to introduce as much information to customers as is required or requested for the consumer to make educated choices in terms of rate offerings and energy usage.

In addition, CHG&E's Customer Service Representatives (CSRs) would have access to the same information the customers are viewing through the web-portal. This provides better insight to the CSRs on the customer's questions and concerns and enables CHG&E to more accurately address the customer call. At the end of the call a confirmation sheet explaining the data discussed during the call can be automatically sent to the customer, again ensuring faster, higher quality service and increased customer satisfaction.

d. Electric Distribution Equipment and Engineering Analysis Software Tool

CHG&E is not new to the concept of Distribution Automation. CHG&E has years of experience with Substation automation through the use of Supervisory Control and Data Acquisition (SCADA) systems and microprocessor based relays with communication capabilities.

Since 2002 CHG&E has been installing Automatic Load Transfer switches (ALTs) and Switched Capacitor Banks (SCBs) on the distribution system. The existing applications utilize radio communication to transmit data between ALT units. The ALTs work in 'teams' of either two or three units and are designed to operate during system faults to reduce the number of customers affected and improve SAIFI. The ALTs, Electronic Reclosers and SCBs transmit data via cell network and are received as either email or text messaging to report status changes or alarms. Data can also be viewed through a vendor-hosted web page in which CHG&E users are assigned user sign in and password information. CHG&E looks to integrate these existing technologies with the Smart Grid project and also build upon the lessons learned during their deployment to avoid unforeseen pitfalls.

CHG&E's investment program will include the installation of substation relaying equipment, SCBs, and electronic reclosers. In addition the project will include integration of communication modules in to existing equipment control panels such as ALTs, SCBs, and voltage regulators.

Overall the project effort will create ten (10) "smart" distribution circuits. Where applicable the circuit upgrades will utilize the existing substation microprocessor based relays, ALTs, and SCBs. The ALTs and SCBs will be retrofitted with communication modules and control devices. Existing fixed capacitor banks will be replaced with the switched style banks with full communication and control capability. Any and all electro-mechanical substation relays will be replaced with microprocessor relays. The relays will be integrated with the existing SCADA system as well as with the data analysis software tool. In addition, the existing normally open tie points between the selected circuits will be replaced with electronic reclosers with communication and control capability in areas where a loop scheme can be created.

Communication modules will be installed in voltage regulator control panels in order to collect and report the voltage and current data that is readily available within the equipment but currently has no means of transmitting the data.

Real-time communication and control with, and between, the distribution equipment will aid in decreasing system losses. Starting from either the substation relays or transformer load tap changer out to the furthest "smart" device, a communication, control, and monitoring system will be created on each circuit. Together these

devices will provide real-time status as well as current and voltage data to the Engineering model but also to be used to create adaptive control schemes whereby the devices can work in tandem to regulate voltage and make the necessary adjustments to load changes driving the circuit to be as efficient as possible by utilizing the newly installed SCBs and communication and control enabled voltage regulators. The newly developed control schemes will eliminate the need for manual intervention and improve the power quality for all customers served by the distribution circuit. The decrease in system losses also drives down the system peak through an improved power factor resulting in longer equipment life. The monitoring and communication enabled equipment can also report back data that can be used to evaluate when the equipment is in need of replacement so that maintenance efforts can be based on actual data rather than statistical maintenance schedules or equipment failures. .

Once the data is verified, it will be collected and integrated into an engineering analysis tool. The tool will utilize the data collected to develop system load flow models to determine the overall health of the circuit, predict overload conditions, high and low voltage events, and power factor discrepancies. The analysis tool can provide suggested remedies to the issues previously listed. It would also be used to identify inconsistencies between load data and OMS. Corrections can then easily be made to OMS and current mapping systems, improving the overall accuracy.

The tool will be used not only by engineering but also by system operators to aid in outage events as well as in every day operations. The operator's ability to monitor and control equipment status will allow them to make smarter decisions, improve the overall circuit reliability, and provide more accurate information to the call center and OMS in response to customer calls.

The end goal of employing the analysis tool is to create a near real-time system model. The model would run continuously analyzing system disturbances, suggesting circuit reconfigurations for load optimization and phase balancing and would have the ability to use the data from the distribution equipment and smart meters to create switching procedures during outage events. It will also be a model that is viewable by numerous departments ensuring that everyone is receiving the same information and encouraging collaboration between work groups.

e. Distributed Resources

The interconnection of distributed resources can impact the utility system in many ways. Introduction of renewables can add "clean" energy sources to the grid, alleviating burden on the existing system and possibly replacing older technologies. Distributed Generation (DG) can also provide back up power in the event of a system disturbance or as a source for demand response by enabling a customer to utilize the generator during system peaks.

Despite the many benefits of distributed generation the detriments of system interconnection can include high voltage, islanding, ferroresonance, and harmonics. Also, CHG&E cannot design their system in a way that relies on the DG unit for generation because there is no guarantee that the source will be available when needed. Therefore it is to the advantage of CHG&E, the generator, and neighboring customers on the circuit that the system as well as the feeder circuit be monitored.

Through the installation of sensing and communication equipment and integration of the data into systems such as OMS and power flow models, CHG&E can recognize and analyze undesirable events as they occur and make the necessary steps to remedy the situation. Through the use of these tools, the speed in which CHG&E responds as well as the service to customers will be drastically improved.

CHG&E has reviewed the existing photovoltaic system interconnections within the service territory and has chosen one of the areas with the largest interconnection concentrations in terms of kW as part of the Smart Grid deployment. Combined with the sensing and communication points, SCBs will be installed to compensate for the DG system by controlling and optimizing the voltage profile of the circuit. The total kW contribution in terms of rated capacity of the existing customer owned PV systems of the selected circuits is 313kW.

In addition to creating advanced control schemes for the existing PV systems, CHG&E will be installing a number of charging stations in the areas described in the "Locations" section. These stations will be used to evaluate demand response through the use of load control devices capable of shutting the system off during peak usage periods. Along with this demonstration, CHG&E hopes to determine the level of consumer interest in plug-in electric vehicles in order to more accurately quantify future system benefits of PEV market saturation.

f. Monitoring of Natural Gas Equipment

Through the installation of communication modules CHG&E will investigate the feasibility and applicability of transferring pressure and flow data from electronic monitors at regulator station and low points through the mesh network.

CHG&E will utilize its existing Electro correctors and IP addressable communication modules in conjunction with the mesh network to transmit data and determine the possibility of installing additional monitoring points. Improved monitoring of the natural gas system will aid CHG&E in delivering gas with increased safety and stability, and aid in design or load flow analysis.

g. Customer Programs

Education and Outreach: CHG&E recognizes that consumers will need guidance through the transition to Smart Grid technologies. With the lack of available energy usage information currently, many customers are unaware of their usage patterns and whether or not they could alter their usage and drive down their costs. Some may be skeptical of the systems being employed for fear of the utility controlling their appliances. These will no doubt be obstacles that CHG&E and customers will have to tackle together.

Beyond the changes customers can make within the home or business, they may not see the benefit of the Smart Grid and the significant investment plans being proposed by utilities may put them off to the idea. Customers have extremely high expectations in terms of reliability already therefore CHG&E will have to find ways to relate the benefits of the Smart Grid as a whole down to a consumer level.

CHG&E intends to educate customers on how altering their usage during peak periods can drive down the cost of energy as well as extend the life of the grid. It is

hard for a consumer to correlate how small changes within their home can increase the lifespan of the distribution transformer they are fed from and in turn the source substation and transmission line. It is the intention of CHG&E to provide this information in a fashion that is easily understood and appreciated.

To aid in the education process, CHG&E is planning a proactive approach. Beyond the standard mailings and bill inserts that will be sent out with details about the various rates, what the HAN and metering equipment is capable of, and energy saving advice; CHG&E will also host public forums prior to deployment where customers can view the equipment and technology demonstrations, sign up for programs, and voice their opinions during a question and answer period or by filling out a survey.

Once the equipment is installed, tested, and validated, CHG&E will continue to provide education and outreach by hosting customer focus groups and creating a dedicated hotline for customers to call in to with questions. The volume of calls will be tracked to determine if additional education and outreach programs are necessary. The CHG&E website will be equipped with the hotline information as well as a list of Frequently Asked Questions and a means to receive additional customer questions and comments.

Demand Response: CHG&E wishes to be explicitly clear that all demand response operations can only be completed with permission and acceptance by the customer to install devices into the home. CHG&E will have two load control devices available to install into the customers homes. The first device is a load control switch that can be installed on a customer's water heater, swimming pool pump, or similar appliance. This switch is intended to be used to prevent the device from operating during peak conditions. The second device is a smart thermostat that will be installed in a customer's premises. This thermostat is intended to shed load during peak conditions by limiting the home's temperature. Both of these devices will have the ability to be manually overridden by the customer, if they choose to do so.

Dynamic Rate Offerings: CHG&E has reviewed the rate offerings of other utilities across the nation and documents such as the "Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure" issued by the California PUC. CHG&E has gained insight into understanding the motivation and expectations of existing rate programs and is developing its own rate offerings that are in tune with its customer's needs as well as those of regulators.

CHG&E proposes multiple dynamic rate structures, as shown in Table 2, to be offered on a voluntary basis to the customer segment described in Control groups 1 through 4 within the "Home Area Network" section of this document.

CHG&E has reviewed the rate structures posed within the DE-FOA-0000058 and is confident that the proposed rate structures are aligned with the DOE goals of involving critical peak pricing. However, since New York State prohibits utilities from mandating customer rates, CHG&E's proposal for offering rates on a voluntary basis is not aligned. CHG&E does not believe that this should discredit the company's proposal. As DOE is encouraging that rate offerings be mandated CHG&E views its position as capable of providing data to evaluate the volunteer niche. To date, customer interest and the true impact of customer initiated demand response has not been established. Through the rate structures and customer segments proposed

by CHG&E these can be tracked and quantified, offering invaluable data for determining the future of Smart Grid through customer involvement.

Supply Rate Type	Existing/New	Description
Standard	Existing	Market Price Charge (MPC) – one static monthly and bi-monthly rates for energy consumption
Time-of-Use (TOU)	Existing – residential only	Static monthly on-peak and off-peak rates based on MPC
Hourly Pricing Provision (HPP)	Existing – SC 2 voluntary	Energy consumption priced by hour based on DAM LBMP for zone G; capacity adder, including working capital and uncollectibles allowance on energy and capacity costs, applied to all energy
HPP/summer peak capacity	New	Energy consumption priced by hour based on DAM LBMP for zone G; capacity costs for the months of June through August recovered during week day hours of 1200 to 1800*
HPP/Critical Peak Pricing (CPP) capacity	New	Energy consumption priced by hour based on DAM LBMP for zone G; capacity costs for the months of June through August recovered during week day hours of 1200 to 1800 and during CPP period events; CPP period events would be called by the Company based on factors such as temperature or system load*

Table 2

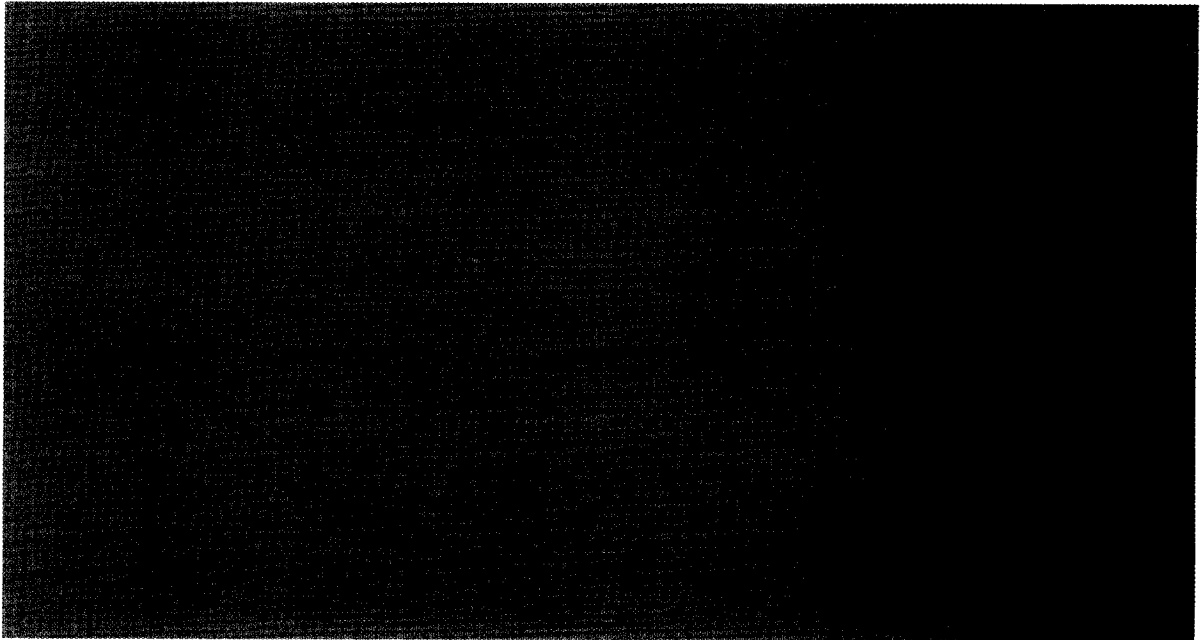
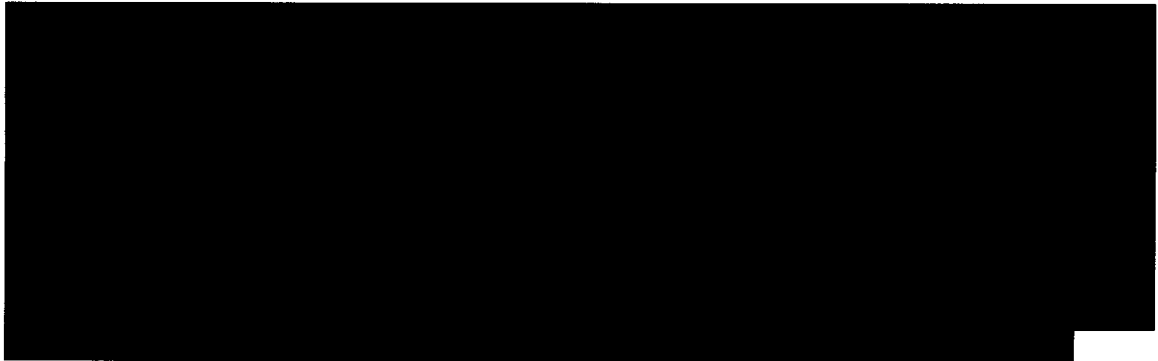
\* Additional response could be induced under these rates by increasing summer capacity costs to approximate rates in capacity-constrained regions. Any difference between actual capacity costs incurred and costs recovered under these rates would be deferred for refund to or surcharge from these customers during the months of September through April. Recovery of costs, other than capacity, currently included in the Company's HPP UCAP factor will be included the capacity factor for these programs.

**Interoperability & Cyber Security**

Interoperability

Interoperability is the capability of two or more networks, systems, devices, applications, or components to share and readily use information securely and effectively with little or no inconvenience to the user.

Information Exchange Interfaces





[Redacted]

[Redacted]

[Redacted]

Openly Available & Legacy Integration

[Redacted]

[Redacted]

[Redacted]

[Redacted]

[Redacted]

[Redacted]

[Redacted]

Future System Impacts

[Redacted]

[Redacted]

[Redacted]

NIST Compatibility

Although CHG&E has laid a foundation for the Smart Grid project planning, NIST's emerging Smart Grid framework for standards and protocols are on the forefront. CHG&E

has reviewed the "Report to NIST on the Smart Grid Interoperability Standards Roadmap" released on June 17, 2009 and has applied strict adherence to the principles set forth in the document. As the NIST Smart Grid roadmap emerges, CHG&E will support and integrate the Smart Grid system to be fully compatible to additional or changing standards.

Cyber Security

Cyber Security is the measures taken to protect a computer or computer system against unauthorized access or attack.

Cyber Security Risk Management

[Redacted]

[Redacted]

[Redacted]

[Redacted]

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Vendor Cyber Security Utilization

[Redacted]

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Security Standards

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## **Project Planning, Progress, and Evaluation**

### **Schedule and Deployment**

Following Commission approval, planning and design, as well as negotiation with the selected system vendors will begin. Critical details such as pricing and performance assurances will be explored during contract negotiation. Vendor equipment orders will then be placed and, following design approval and equipment delivery, installation will begin.

Among other details, the negotiation process will establish the functional baselines for data gathering and analysis, defining the extent and detail level of expected vendor support. Vendor responsibilities will include but not be limited to development of an optimized equipment layout based on deployment locations provided, training of CHG&E resources, customer support, and project management assistance.

In collaboration with the selected suppliers, CHG&E will create a repository for all collected data, and will define queries to generate the statistics to be reported. Backup procedures will be defined to protect the project from data loss. These procedures will be exercised before the start of deployment operations.

System deployment will consist of four main components, as follows. The first three will take place concurrently, and the fourth will be conducted after a substantial amount of endpoints have been installed.

1. Meters, Distribution Equipment, and Communication Modules
2. Communications Infrastructure
3. Operating System Software and Head-End System
4. Data Process Validation

As the equipment is deployed, CHG&E and the equipment vendors will work together to ensure proper installation as well as the integrity of the communication infrastructure. The systems will be monitored during installation to track communication capability back to the head-end. Once all equipment has been installed and any communication issues resolved the data process validation phase will begin.

During the data validation phase, CHG&E will begin registration for the various customer programs such as dynamic rates and home area network equipment installation. These programs are dependant on the proper operation of the communication and metering systems, therefore it is best to delay their availability until the head-end systems have been proven.

The final data process validation will be conducted with data gathered by the newly installed and operational Smart Grid system. During this process, tests for outage detection, restoration reporting, control capabilities, and various other functions will be defined and implemented. In terms of the meter remote disconnect/reconnect capabilities, CHG&E intends to follow all procedures as outlined by the Home Energy Fair Practices Act (HEFPA). CHG&E will have a representative present when testing all control features in order to ensure proper operation.

The accumulated data will be examined to determine if it can provide additional benefit with respect to meter tampering, meter performance, and distribution system performance.

There has been a significant increase in production volume for the Smart Grid industry due to the availability for ARRA funding, but CHG&E anticipates the necessary equipment can

likely be available for installation 90 days from Commission approval. Concurrently, CHG&E will request bids from contractors for the meter and HAN equipment installation and will draw up a contract upon selection of an installer. Internal CHG&E resources will complete all distribution equipment as well as specialized meter installs.

Overall, the project is to be completed within a three (3) year timeframe as outlined in the DE-FOA-0000058. The project timeline including all reporting and significant milestones is included in Table 7 below. It is important to note that the itemized project start times can be altered to better fit the requirements of the DOE if necessary.

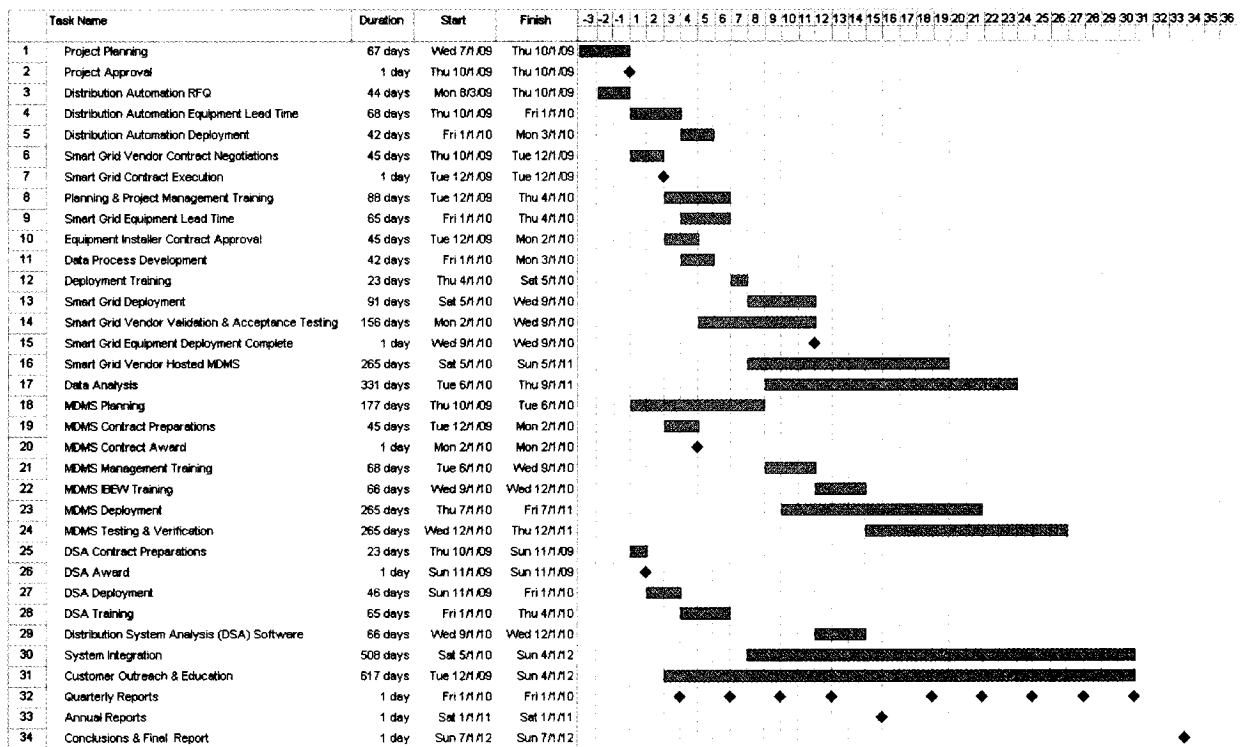


Table 7

### Systems Evaluation

The evaluation effort is expected to involve interviews with CHG&E managers and staff, discussions with all system vendors, and comparisons to published results of other Smart Grid deployments and trials of similar scope. The results of the analyses will be accumulated and reported as required by DOE. If other opportunities arise to establish quantitative measures of the Smart Grid systems deployed, CHG&E will consider pursuing them.

There are certain criteria that the Smart Grid technology or application must meet in order to prove a worthwhile technology for future deployment consideration. The systems and equipment deployed will be evaluated according to the following criteria:

- ❑ **Influence on current business practices**

Ability of equipment meet existing work process needs as well as to aid in efforts to increase efficiency, productivity, and task optimization methods.
- ❑ **Receptivity**

Ability for all approved users to interface with and operate the specified application as well as interoperability with internal programs and legacy systems.
- ❑ **Standardization**

Non-proprietary system that uses industry standardized methods, can adhere to future standards, and is certified according to standardized test procedures.
- ❑ **Scalability**

Ability to facilitate full system deployment, is updatable, and can co-exist or improve the operation of legacy systems.
- ❑ **Adaptability**

Ability of the system to detect and adapt to system changes without sacrificing performance.
- ❑ **Security**

Ability to transmit data through multiple communication layers without jeopardizing the integrity of the data being sent or the system receivers. Application is capable of multi-user access for varying permission levels. Meets NIST requirements and is adaptable to future security standards.
- ❑ **Cost-Effectiveness**

Ability to see a rate of return on investment through the combination of hard and soft benefits. Application offers a means of reducing installation, maintenance, or operating costs while enabling new business, product or service opportunities.
- ❑ **Manageability and Upgradeability**

Application meets performance expectations as outlined in contractual agreements. Offers capability to upgrade or integrate new technologies in the future.
- ❑ **Interactivity**

Encourages consumer interaction and adoption and is presented in a user-friendly format.
- ❑ **Communication performance**

The application is reliable and stable, has the capability to recover data during communication breakdowns and operate during system disturbances, minimal impact of communication disturbances on data transfer latency.

The performance in each category will be used to determine the potential for continued use as well as additional future applications.

Additionally, in order to track project performance CHG&E will follow the metric guidelines as defined in the DE-FOA-0000058 in terms of customer-level metrics and distribution-level metrics.

Management Team

CHG&E has assembled an interdisciplinary work team of varying experience and knowledge levels to carry out the Smart Grid program plan. Chart 1 below describes the organizational structure. Attachment II includes a description of each team member and their project responsibilities.

To supplement the project team areas of expertise, CHG&E may pursue consulting services.

**CHG&E Smart Grid Team Organization**

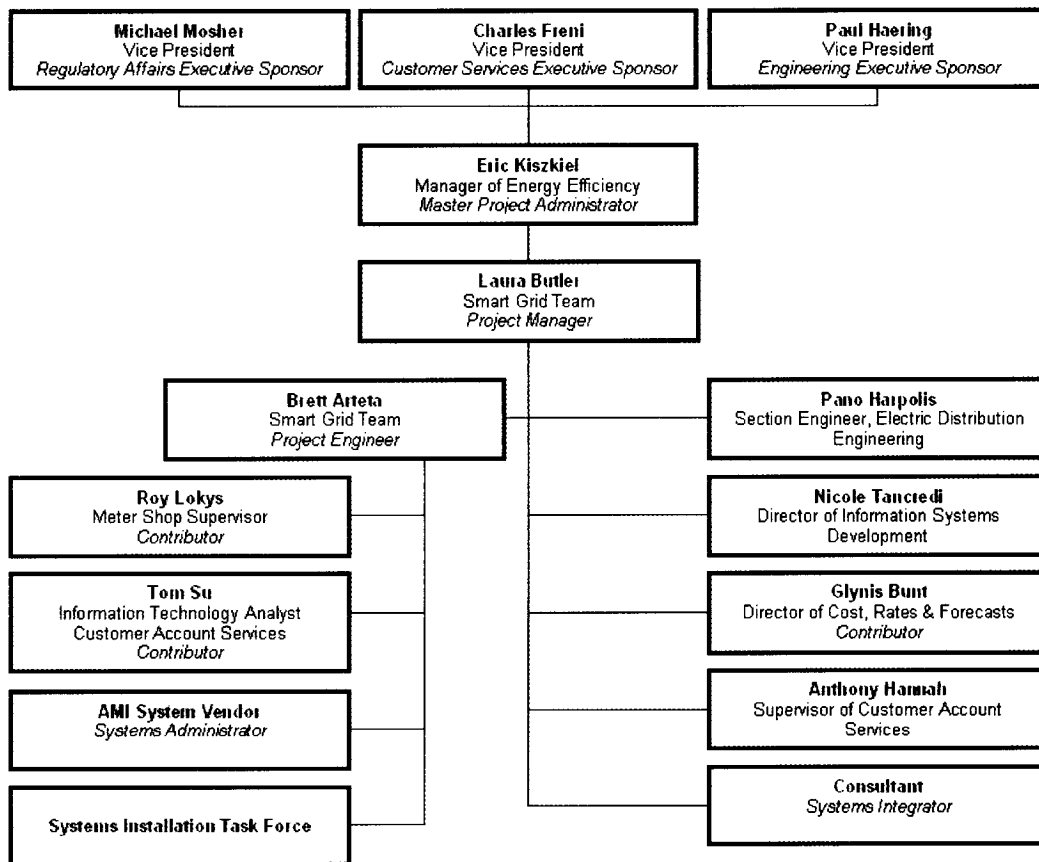


Chart 1

Project Risks and Mitigation Plan

CHG&E has considered the numerous risk factors associated with the application and integration of new technology. Risk can be determined according to the following process categories: business, technology, complexity, organization, operational, and schedule. Due to the novelty of Smart Grid technologies many of the project characteristics fall in to the

high-risk zone, see Attachment III. This could be viewed as a red flag against the project unless there are ample means for mitigating the associated risks.

Table 8 describes the risk classifications, potential impacts and associated mitigation techniques that CHG&E has considered.

<b>Risk Category</b>	<b>Description</b>	<b>Potential Impact</b>	<b>Mitigation</b>
Business	Lack of interest in new services and programs	Limited number of participants prohibits collection of sufficient data	<ul style="list-style-type: none"> <li>▪ Provide numerous levels of and opportunities for customer education and outreach</li> <li>▪ Track need for increased education and outreach programs and work towards appropriate program enrollment levels</li> </ul>
Technology	Technology does not meet performance expectations	Stranded Investment	<ul style="list-style-type: none"> <li>▪ Develop performance criteria and resolution plan with vendor during contract phase</li> <li>▪ Evaluate vendor according to agreed upon criteria and maintain accountability</li> <li>▪ Meter cost will eventually be realized due to the basic functions independent of the AMI system performance</li> </ul>
Complexity	Integration of multiple new technologies	Lack of Interoperability	<ul style="list-style-type: none"> <li>▪ Employ technologies that are non-proprietary, use open protocols and adhere to current industry standards</li> <li>▪ Exploit remote firmware upgrade capabilities</li> <li>▪ Review alternative solutions in the event the chosen technologies cannot perform as necessary</li> </ul>
Organizational	Limited resource availability	Impact to organizational roles or staffing levels	<ul style="list-style-type: none"> <li>▪ Development of dedicated internal resources</li> <li>▪ Perform gap analysis and pursue support in the form of consulting services or contractors</li> <li>▪ Utilize vendor representative availability and resource offerings</li> </ul>
Operational	High start up costs and limited funding	Heavy price tag deters regulatory and organizational support	<ul style="list-style-type: none"> <li>▪ Pilot size proposal rather than full deployment limits investment risk</li> </ul>
	Safety	Endangering persons, property, or the public	<ul style="list-style-type: none"> <li>▪ Creation of standards for all newly installed equipment</li> <li>▪ Development of internal training programs</li> <li>▪ Customer education and outreach plans</li> <li>▪ All work to be performed within all local, state, and federal codes and guidelines (OSHA, NESC, etc.)</li> </ul>
Schedule	Vendor cannot supply desired equipment quantities from manufacturer	Project schedule delay and budget overrun	<ul style="list-style-type: none"> <li>▪ Limited scale of desired quantities</li> <li>▪ Manufacturer agnostic</li> <li>▪ Equipment installation can occur concurrent to other operations without negatively impacting the schedule</li> </ul>
	Equipment shipping delays	Project schedule delay and budget overrun	<ul style="list-style-type: none"> <li>▪ Multi-phased integration does not require simultaneous equipment installation</li> <li>▪ Use of multiple equipment providers limits likelihood of delays</li> <li>▪ Contracts contingent upon delivery schedules</li> </ul>

Table 8

### Reporting

All quarterly and annual reports as well as the final report will be structured and submitted to meet the requirements and deadlines as defined by DOE.

CHG&E will also develop a Business Case document assessing the impact of a saturation implementation of Smart Grid technologies throughout the service territory along with a compilation of lessons learned.

### Cost Benefit

Benefits can be evaluated in terms of system, societal, and environmental impacts.

#### System Benefits

Remote monitoring, data collection, and operation of equipment offer a potentially significant decrease in operating costs due to the decrease in truck rolls to “troubleshoot” and repair equipment failures. Not only can field visits be avoided but operators can also change from a reactive approach to reliability to a proactive/predictive approach, replacing equipment prior to failure.

Use of the data collected in conjunction with the analysis tool can aid in prolonging the life of the grid and determining the need for infrastructure improvements based on real-time usage information rather than historic load patterns, load growth surveys, and equipment failures.

#### Societal Benefits

In terms of societal benefits, the expectation is that both the utility and customers alike will become comfortable and proficient in use of the new systems. Leading to better consumer-utility relations through improved communications and billing accuracy, improved response times through more accurate data received by OMS, and increased reliability and efficiency of the overall grid through evaluation of the distribution system data collected and potential for peak load shifting through increased customer involvement and understanding. If peak shifting is successful operating costs can be driven down and customers will be able to share in those cost savings.

Through consumer outreach and education programs customer satisfaction can be increased. Customers will be provided with the tools to make informed decisions creating an empowered and engaged consumer that can make an effort to change his or her usage pattern and see the results of his or her effort in the next bill.

#### Environmental Benefits

By deploying Smart Grid devices, many environmental benefits will be observed but will be difficult to quantify. With increased asset utilization made possible through smart energy management, more efficient power plant operation and fewer peaking units can be made possible. Moreover, the increased ability to manage load effectively with new Smart Grid

system equipment can result in utilities delaying or eliminating the need for building new infrastructure to serve peak hours of the year.

With Smart Grid controls and adaptive operation and protection schemes, distributed generation can be dynamically managed and integrated with the grid more efficiently. Through demand response efforts the ability to establish a power market by stabilizing the power consumption in an area can be accomplished. Preparing the system for the introduction of distributed energy resources will enable clean energy generation to participate in the new power market more effectively, in turn facilitating state and countrywide green energy goals.

CHG&E has cost-benefit expectations aligned and in accordance with the benefit categories detailed in Table 6 of the DE-FOA-000058. Table 9 below describes these expectations.

Benefit Category	Potential Benefit	Expected Benefit*	Reporting Data
Economic	Lower electricity cost with lower peak demand	<ul style="list-style-type: none"> <li>Collect and evaluate consumer involvement in demand response programs to determine benefit of system wide program availability</li> </ul>	<ul style="list-style-type: none"> <li>Customer hourly load</li> <li>Customer monthly electricity cost</li> <li>Customer tariff description</li> <li>Customer demographic</li> <li>Concentration and Use of smart appliances</li> </ul>
	Lower T&D Losses	Reduce losses by 6520 MWh**	<ul style="list-style-type: none"> <li>System Losses (MWh)</li> <li>% of MWh served by DG</li> </ul>
	Lower O&M Costs	Lower by approximately \$150,000 per year from MH avoided	<ul style="list-style-type: none"> <li>Activity based O&amp;M costs</li> <li>Equipment failure incidents (non-storm related)</li> </ul>
Reliability and Power Quality	Reduced cost of power interruptions	Mandated metrics will be met and regulatory penalties avoided	<ul style="list-style-type: none"> <li>SAIFI</li> <li>SAIDI or CAIDI</li> </ul>
	Reduced costs from better power quality	<ul style="list-style-type: none"> <li>Reduced interruptions to commercial and industrial customers and losses associated to interrupted business processes</li> <li>Stabilize availability of customer PV systems through voltage control applications</li> </ul>	<ul style="list-style-type: none"> <li>MAIFI</li> <li>Comparison of individual customer PV system availability to historic net metering data based on voltage levels</li> </ul>
Environmental	Reduced damages as a result of lower GHG/carbon emissions	TBD	<ul style="list-style-type: none"> <li>Hourly consumption against baseline/control group</li> <li>% of MWh served by DG</li> <li>T&amp;D system losses (MWh)</li> <li>% of MWh served by RE</li> <li>% of feeder peak load served by RE</li> <li>Average heat rate of supply (or similar information)</li> </ul>
Energy Security	Greater energy security from reduced oil consumption	TBD	<ul style="list-style-type: none"> <li>KWh of electricity consumed by PHEVs</li> </ul>

Table 9

\* All Expected Benefits are in terms of utility savings and are based on percentages derived from the number of distribution circuits and customers included in the Smart Grid project compared to system totals.

\*\* Based on 21.76 MWh per circuit-mile loss.

### **Project Cost**

Taking in to account the costs associated with the necessary Vendors, Contractors, Consultants as well as internal costs for CHG&E resources, the per endpoint cost is expected to be approximately \$1,342. The total project cost is estimated to be \$17.3 million (Table 10).

Due to the initial start up costs and limited number of endpoints associated with a deployment of the proposed size, the cost per endpoint is much higher than it would be for full deployment.

CHG&E proposes and expects to request funding from the competitive grant process of the U.S. Department of Energy's Electricity Delivery and Energy Reliability (EDER) program established by the American Reliability and Recovery Act of 2009, through the Investment Grant funding opportunity, DE-FOA-0000058, which can provide funding of up to 50 percent of the costs of qualified investments to successful applicants. The Company proposes to defer the balance of the Smart Grid electric program costs, including internal labor, not funded by the EDER program grant and recover the balance by charging the net regulatory liability owed to customers that will be available at the conclusion of CHG&E's pending rate case. In addition, CHG&E proposes that any Smart Grid gas costs be deferred and recovered from customers at a later date.

Description	Quantity	Per Unit Cost	Wk Hrs	Crew Size	Labor Costs Straight Time	Overtime	Days	Overhead Rates	Cost
<b>Planning</b>									
<b>Time</b>									
Customer Accounting									
Customer Outreach									
Intern									
IT									
Project Management									
Engineering									
Purchasing									
Rate Creation									
Training Program									
Vendor PM, Training, Sys Integration & RF Studies									
Management Approvals									
<b>Materials</b>									
Energy Usage Display									
Eval, Meas, Verify Services									
MDM Licensing & Service Fees									
MDMS									
Customer Portal									
Annual Fees									
Carbon Footprint Calculator									
Annual Fees									
Load Flow Software									
Concentrator									
Repeater									
Field Tool Software									
Res Meter & Comm Mod									
DA Mod sensors									
DAP Install Tools									
Gas Meter Modules									
PolyPhase Meter & Mod									
Smart Grid Business Case Svcs									
Smart Thermostat									
Smart Water Heater Device									
Web System									
WAN Extender									
WAN Gateway									
Remote Disconnect/Reconnect									
Electronic Recloser (set of 3)									
Automatic Switched Capacitor Bank									
Fault Indicator									
Substation Relay Panel									
Charging Station									
<b>Deployment</b>									
Contract HAN Installer									
Contract Meter Installer									
Project Management									
Meter Testers									
Foremen									
Training									
Pen Computers									
IT									
Pole-mounted Installs									
System Integrator									
Engineering									
<b>Operations &amp; Maintenance</b>									
Foremen									
IT									
Project Management									
Meter Testers									
Focus Groups									
Engineering									
<b>Evaluation &amp; Reporting</b>									
Consultant - Customer Study									
Project Management									
Management Review									
Engineering									
<b>A&amp;A</b>									
<b>Subtotal</b>									
<b>Contingency</b>									
<b>Total Cost</b>									\$17,328,664

Table 10

## **Recommendations**

The project described herein by CHG&E satisfies the criteria necessary to be considered a Smart Grid Investment Program project as defined by the DOE in DE-FOA-0000058. In addition, the project addresses the requirements and concerns of FERC, NIST, and the NYS Commission.

CHG&E's project encompasses multiple facets of Smart Grid including:

- Electric distribution automation
- Electric distribution data monitoring and analysis
- Integration of new and legacy systems through the adoption of an MDMS
- Collaboration and work efficiency improvements through multi-user access to the MDMS and data analysis tool
- Real-time data access by both CHG&E and the customer through the AMI and HAN infrastructure
- Dynamic rates and demand response program offerings

Combined, these demonstrations will enable both CHG&E and consumers a mechanism for each to be better stewards of not only New York's but the nation's energy needs. Therefore, it is the recommendation of CHG&E that this project be approved for funding and implementation.

## **Attachments**

- I. Smart Grid Project Abstract
- II. CHG&E Smart Grid Project Team Description
- III. Risk Assessment Spreadsheet