Raquel J. Webster
Senior Counsel

February 25, 2014

BY HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4473 - National Grid's Proposed FY 2015 Electric Infrastructure, Safety, and Reliability Plan
Responses to PUC Data Requests – Set 2

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's responses to the Public Utilities Commission's ("PUC") Second Set of Data Requests in the above-referenced proceeding.

Please be advised that the Company is seeking protective treatment of the confidential version of Attachment PUC 2-8 provided in response to PUC Data Request 2-8, as permitted by PUC Rule 1.2(g) and by R.I.G.L. § 38-2-2(4)(i)(B). For the PUC's review, the Company has submitted a Motion for Protective Treatment along with a copy of the confidential version of Attachment PUC 2-8 pending a determination on the Company's Motion. The Company is not seeking confidential treatment for the data included in the Company's written response to PUC Data Request 2-8; only the un-redacted version of Attachment PUC 2-8 is confidential.

Thank you for your attention to this transmittal. If you have any questions, please contact me at (781) 907-2121.

Very truly yours,

Raquel J. Webster

Enclosures
cc: Docket 4473 Service List
Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth, Division

[1] The Narragansett Electric Company d/b/a National Grid "National Grid" or the "Company").

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2121 ■ raquel.webster@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and/or any materials accompanying this certificate were electronically transmitted to the individuals listed below.

Copies of this filing will be hand delivered to the RI Public Utilities Commission and to the RI Division of Public Utilities and Carriers.

Joanne M. Scanlon

February 25, 2014

Docket No. 4473 National Grid's FY 2015 Electric Infrastructure, Safety and Reliability Plan - Service List as of 01/07/14

Name/Address	E-mail Distribution	Phone
Thomas Teehan, Esq. National Grid. 280 Melrose St. Providence, RI 02907	Thomas.teehan@nationalgrid.com celia.obrien@nationalgrid.com raquel.webster@nationalgrid.com Joanne.scanlon@nationalgrid.com	401-784-7667
Jennifer Grimsley Ryan Moe Sean Nestor	Jennifer.grimsley@nationalgrid.com Ryan.moe@nationalgrid.com John.nestor@nationalgrid.com	
Leo Wold, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov Sscialabba@dpuc.ri.gov Jlanni@dpuc.ri.gov Jshilling@dpuc.ri.gov Jspirito@dpuc.ri.gov dmacrae@riag.ri.gov Jmunoz@riag.ri.gov	401-222-2424
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com	603-964-6526
Greg Booth PowerServices, Inc 1616 E. Millbrook Road, Suite 210 Raleigh, NC 27609	gbooth@powerservices.com	919-256-5900
File an original & 11 copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov Cynthia.WilsonFrias@puc.ri.gov Alan.nault@puc.ri.gov	401-780-2107

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
RHODE ISLAND PUBLIC UTILITIES COMMISSION

FY 2015 Proposed Electric ISR Plan **Docket No. 4473**

NATIONAL GRID'S MOTION FOR PROTECTIVE TREATMENT
OF CONFIDENTIAL INFORMATION

National Grid[1] respectfully requests that the Rhode Island Public Utilities Commission ("the PUC") provide confidential treatment and grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(B). National Grid also respectfully requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On February 25, 2014, National Grid is filing with the PUC its responses to the PUC's Second Set of Data Requests in this matter. In PUC Data Request 2-8, the PUC requests information regarding the Company's Request for Proposal ("RFP") in connection with the Company's Volt/VAR Optimization Demonstration Project (the "Project"). Specifically, the PUC requests a copy of the RFP for the Project, the components of the Project budget, the number of bidders, and the review process for choosing the winning bidder, Utilidata.

In responding to PUC Data Request 2-8, the Company has submitted as confidential version of Attachment PUC 2-8 Utilidata's Statement of Work ("SOW") for the Project. This SOW includes competitive and proprietary financial information such as total Project costs and professional service fees for the Project consultants; it also includes information concerning the Company's base rates relating to those costs and service fees. *See* confidential version of Attachment PUC 2-8 at section 1.14. Under National Grid's arrangement with Utilidata, the financial information included in section 1.14 of the SOW is considered proprietary. Therefore, National Grid requests that the PUC treat the information contained in Attachment PUC 2-8 as confidential.

II. LEGAL STANDARD

The PUC's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I.G.L. §38-2-1 *et seq.* Under the APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of the APRA to treat such information as confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(B) provides that the following types of records shall not be deemed public:

[1] The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company").

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would likely either (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

II. BASIS FOR CONFIDENTIALITY

The information regarding the Project financials included in Attachment PUC 2-8 was provided to National Grid on a confidential basis as part of the RFP process for the Project. National Grid is providing confidential version of Attachment PUC 2-8 to the PUC and the Division on a voluntary basis to assist the PUC with its decision-making in this proceeding. Disclosure of this information could adversely affect Utilidata's competitive position and would tend to make it less likely that such information would be provided voluntarily in the future. Moreover, such disclosure would impede National Grid's future ability to obtain this type of proprietary information from bidders and third-party consultants, or would increase the cost at which that information could be obtained.

III. CONCLUSION

Accordingly, the Company requests that the PUC grant protective treatment to confidential un-redacted version of Attachment PUC 2-8.

WHEREFORE, the Company respectfully requests that the PUC grant its Motion for Protective Treatment of Attachment PUC 2-8.

Respectfully submitted,

NATIONAL GRID

By its attorneys,

Raquel J. Webster, RI Bar # 9064
Thomas R. Teehan, RI Bar # 4698
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7288

Dated: February 25, 2014

PUC 2-1

Request:

In Docket No. 4442, National Grid's witness testified that if there is a pole that cannot handle an attachment, "the field survey would identify that the available space or the loaded conditions are such that would require changes being made to the infrastructure to support the proposed change, and the company would then provide make-ready cost for whatever appropriate changes are required to facilitate the capability of attaching that proposed attachment to that pole. The last person seeking an attachment "is responsible to compensate all parties that have some relative work required to accommodate them as a future attacher" and if a new pole is required, "the future attacher would be responsible for the cost of that change-out of the pole and all of the relocations of all of the existing attachers to that new pole." (Transcript 12/3/13 at 139-40). On page 43 of the proposed FY 2015 ISR plan, there is the following statement: "Spending to enable third-party attachments is highly variable year-to-year based on the timing of the contributions from third parties and the cost to make sure that the Company's assets meet the standards required to enable the attachments. The latter is not reimbursed by third party customers and as such may increase the balance spent within this category." Please explain the difference in the two scenarios where the first appears to expect reimbursement to the company and the second has an exception to that.

Response:

National Grid performs field surveys and assessments on all poles to which third parties request attachments. These surveys capture the existing heights of all pole attachments, pole height and class, as well as any pre-existing, non-conforming conditions. The results of the field survey and pole loading analysis are analyzed and a make-ready work scope is developed, which will outline for each pole, any necessary make-ready work required to accommodate the new third-party attachment. If make-ready work is required, it is categorized as reimbursable make-ready or non-reimbursable make-ready.

Reimbursable make-ready would be make-ready work that is reimbursable to National Grid to accommodate a new third-party attachment. This includes all costs associated with the pole replacement including, permitting, material, labor, engineering, site protection, removal and disposal of the existing pole, and transfers to the new pole. It could also include shifting of facilities at an existing pole. In Rhode Island, National Grid recovers all costs for poles that require reimbursable make-ready.

Non-reimbursable make-ready is work that is not reimbursable to National Grid. This non-reimbursable work is mandatory for National Grid to address pre-existing, non-conforming conditions that require corrective action before attachments can be safely made by the third party. This corrective action is mandatory to ensure compliance with the National Electric Safety Code

PUC 2-1, page 2

("NESC"). An example of pre-existing conditions could be an inadequate pole due to deterioration, age, or other conditions. Another example would be the existing pole height which does not maintain the minimum NESC separation requirements.

Non-conforming conditions are situations in which the current pole is not adequate for the existing attachments, either due to minimum separation requirements at the pole, within the span or loading. It becomes the responsibility of the pole owners to correct all non-confirming conditions identified during the field survey for the third party application. The corrective action could vary depending on the condition from major work like a pole replacement which would include pole removal/disposal, material, labor, engineering, permitting fees, site protection, and the transfer of all facilities or minor work which would include shifts of equipment up or down on the existing pole.

PUC 2-2

Request:

What is the criteria for determining when reactive "fix on failure" (mandatory spending) evolves into proactive replacement of an entire circuit or a localized portion of a circuit (discretionary spending)? (p. 46)

Response:

Fix on failure activities are those emergency activities required to restore customers. The work is limited to the specific failed equipment to enable expeditious customer restoration.

There is no formal criteria for determining when reactive "fix on failure" (mandatory spending) evolves into proactive replacement of an entire circuit or a localized portion of a circuit (discretionary spending). Generally, the Company proposes underground cable replacement projects based on customer, safety, asset condition, and reliability considerations. Following a reactive "fix on failure" event, one or more of these categories can be and are often refined. For example, the asset condition of surrounding cable sections could be negatively impacted by the nearby fault, customer impacts could be refined based on construction logistics, or if previously unknown safety issues arise. Combined with the local knowledge of the crews and engineering staff, these and other reasons often turn a specific cable section repair into an asset condition driven project to address the remaining or other area cable sections.

However, it should be noted that where certain work is categorized as "discretionary spending," the work is ultimately ongoing required, non-discretionary work that an electric distribution utility must perform to ensure safe and reliable service to customers. The only discretion is around the appropriate timing and prioritization of the work that is ultimately necessary to be performed.

Prepared by or under the supervision of: Jennifer L. Grimsley

PUC 2-3

Request:

With regard to the Distribution Substation Replacement, exactly how many battery systems does the Company have? How many batteries are 20 years or older? Are there any batteries which are not 20 years or older but do not meet the Company's current operating requirements and perform their designed function? If yes, how many? How old are these batteries?

Response:

The Company has 86 battery systems, and none are 20 years or older. There are presently two battery systems that do not meet the Company's current operating requirements and need replacement due to poor condition and reliability. The battery bank at Geneva #71 has corrosion on the posts and broken straps. This is an early indication of battery failure. This battery has 16 years of in-service operation. The battery bank at Merton #51, which is presently 15 years-old, is a design that is not expected to last 20 years of in-service operation. Replacement of both battery systems is in-progress.

PUC 2-4

Request:

How many distribution substation batteries were scheduled to be replaced in FY 2014? How many were replaced? How many are scheduled to be replaced in FY 2015 with a $250,000 budget? (p. 46)

Response:

In FY 2014, there were three battery systems scheduled to be replaced – Merton #51, Geneva #71, and Lincoln Ave #72. Of these three scheduled replacements, Lincoln Ave #72 has been completed and the other two are in-progress. In addition, four battery system replacements, which were scheduled for FY 2013, were completed in FY 2014.

Presently, one additional battery system is scheduled for replacement in FY 2015 at Navy 1 substation. Although there is only one battery scheduled for replacement in FY 2015, it is not unusual to have one or two additional locations require replacement due to an asset condition issue.

PUC 2-5

Request:

What is the criteria for determining which transformers need to be proactively replaced? In other words, how have the asset condition issues been identified and how were the assets prioritized? (p.50)

Response:

The criteria used to determine which transformers require proactive replacement is based upon the health and risk (consequence of failure) of the transformer. A desktop analysis is performed using various inputs such as main tank and load tap changer Dissolved Gas Analysis ("DGA"), Oil screen, Furan tests, dielectric tests, known design issues, age, and operating history to determine the health of each transformer. Inputs such as customers served, PCB contamination, contingency plan, and transformer loading are used to determine the risk. The inputs are scored on a non-linear scale and each transformer is ranked. A review is conducted with Subject Matter Experts ("SME") twice yearly on the transformers with elevated scores. The outcome of the desktop analysis and review with SMEs will determine which transformer will be replaced and when.

PUC 2-6

Request:

For each of the most significant Load Relief Projects for FY 2015 described on pages 57-60 of the proposed FY 2015 ISR plan, please provide a summary of the work that will be completed on each project in FY 2015, any work that took place in FY 2014 and the associated cost, and when the project is anticipated to be completed and at what cost.

Response:

Costs shown in the responses below are distribution capital costs, and align with the Company's response to Division 1-15 and Division 1-16. FY 2014 distribution capital forecasts are based on information through the third quarter of FY 2014.

New London Avenue Substation:

FY14 Work Completed:
Land acquisition for the new substation was completed and preliminary engineering is expected to substantially complete by the end of FY14.

FY14 Distribution Capital Forecast: Approximately $220,000.

FY15 Work Planned:
Work planned for FY15 includes final engineering, permitting, and procurement activities.

Anticipated Completion Date: January 2017

Projected Total Distribution Capital Cost: Approximately $4.8 million

Chase Hill Substation:

FY14 Work Completed:
Land was acquired to locate the substation, archeological and noise studies were completed, environmental permitting applications were drafted, and detailed engineering was initiated.

FY14 Distribution Capital Forecast: Approximately $2.1 million dependent on the timing of major equipment procurement currently expected just prior to the end of FY14.

PUC 2-6, page 2

FY15 Work Planned:
The work planned for FY15 includes the submittal/approval of environmental permitting, the completion of design, finalizing major equipment purchases and construction of the civil works.

Anticipated Completion Date: March 2019
Projected Total Distribution Capital Cost: Approximately $26.0 million

Newport Substation:

FY14 Work Completed:
Work completed in FY14 includes preliminary design for phase 1 of the substation, preliminary design for the first transmission tap to the proposed substation, and the zoning amendment for the substation with the City of Newport.

FY14 Distribution Capital Forecast: $200,000

FY15 Work Planned:
Work planned for FY15 includes modification of lease agreement with existing tenant on proposed substation site, continuation of design, material procurement and preliminary construction activities for phase 1 of the substation

Anticipated Completion Date: December 2018

Projected Total Distribution Capital Cost: Approximately $28.6 million

Johnston Substation Project:

FY14 Work Completed:
Work completed in FY14 includes transformer installation, and a portion of the getaway conduit work.

FY14 Distribution Capital Forecast: Approximately $3.5 million

FY15 Work Planned:
Work planned for FY15 includes installation of the new feeder, retirement and removal of all equipment in the old 12.47 kV substation, completion of 2 feeder bays in the new substation yard including substation capacitor banks.

Anticipated Completion Date: October 2014 (revised from August 2014 as shown in response to Division 1-15 and Division 1-16).

Projected Total Distribution Capital Cost: Approximately $6.5 million

Kilvert Street Substation:

FY14 Work Completed:
FY14 work includes a portion of the substation final engineering and design activities and the ordering of the major station equipment. Additionally, approximately half of the distribution line work was completed in FY14.

FY14 Distribution Capital Forecast: Approximately $2.0 million

FY15 Work Planned:
Work planned for FY15 includes completion of the substation final engineering and design, major material procurement, permitting, and initial construction activities. The distribution line work will be completed in FY15.

Anticipated Completion Date: November 2015 (revised from August 2015 as shown in as shown in response to Division 1-15 and Division 1-16.

Projected Total Distribution Capital Cost: Approximately $6.8 million

Kent County Substation:
FY14 Work Completed:
FY14 work includes preliminary engineering activities.

FY14 Distribution Capital Forecast: Approximately $130,000.

FY15 Work Planned:
Work planned for FY15 includes final engineering and design and ordering of major material.

Anticipated Completion Date: August 2016.

Projected Total Distribution Capital Cost: Approximately $3.6 million

PUC 2-6, page 4

Highland Park Substation:

FY14 Work Completed:
FY14 work includes completion of the majority of the civil work and the foundation work inside the substation site. Installation of all the primary conduit inside the substation along with the needed conduits along Highland Corporate Park Drive are complete. In addition, approximately half of the aluminum structures will be installed, and most of the major equipment will be on their corresponding foundations.

FY14 Distribution Capital Forecast: Approximately $7.1 million

FY15 Work Planned:
Work planned for FY15 includes completion of the civil work, installation of the remaining aluminum structures, installation of the control house, installation of the transmission line structures, and complete commissioning activities.

Anticipated Completion Date:
The current targeted completion date for the substation and line portion of the work for the customer is June 15, 2014. The remaining line work will require several additional months for completion.

Projected Total Distribution Capital Cost: Approximately $14.2 million (revised from $6.5 million as shown in Division 1-15 and Division 1-16 due to correction of costs between transmission and distribution as discussed in quarterly updates and refinement of costs from conceptual grade estimates).

Clarke Street Substation:

FY14 Work Completed:
FY14 work includes completion of preliminary engineering, ordering of major equipment, and initiation of final engineering and design.

FY14 Distribution Capital Forecast: Approximately $200,000

FY15 Work Planned:
Work planned for FY15 includes completion of final design, material procurement and construction.

Anticipated Completion Date: March 2015 (revised from January 2015 as shown in response to Division 1-15 and Division 1-16.)
Projected Total Distribution Capital Cost: Approximately $1.3 million

PUC 2-7

Request:

The FY 2014 Electric ISR anticipated targeting nine substations for SCADA additions at a budget of $1 million. Four of those substations are included in the SCADA program for FY 2015, which targets twelve substations and anticipates starting preliminary engineering for five more at a total budget of $1.7 million. Please indicate how many substations received SCADA additions in FY 2014, why the four substations are being carried over for an additional year, and the likelihood that the additional work will be able to be completed in FY 2015. (p. 63)

Response:

Stations receiving SCADA additions under the EMS Expansion/RTU Installation Program have a project duration of two to three years depending upon the scope of the project. Expansions may be shorter in a small station whereas new installations will take the full three-year timeframe. Old Baptist #46 station is very close to completion and will be placed in service in late FY 2014 or early FY 2015. None of the other ongoing SCADA addition projects are expected to be placed in service in FY 2014. Five additional substations are expected to be completed and placed in service in FY 2015: Division #64, Natick #29, Lincoln #72, Elmwood Outdoor #7, and Peacedale #59. Below is a table listing the SCADA addition projects and their statuses:

Substation Location	Scope	Status
Natick 29	Expansion	Final Engineering
Hospital 146	Installation	Final Engineering
Peacedale 59	Expansion	Final Engineering
Division St 64	Expansion	Final Engineering
Old Baptist 46	Expansion	Construction
Lincoln Ave. 72	Expansion	Final Engineering
Hopkins Hill	Expansion	Preliminary Engineering
Harrison 32	Installation	Preliminary Engineering
South Aquidneck 122	Installation	Hold - Possible Retirement
North Aquidneck 21	Installation	Hold - Possible Retirement
Davisville	Expansion	Preliminary Engineering
Rochambeau Avenue 37	Installation	Preliminary Engineering
Clarkson	Expansion	Preliminary Engineering
Warwick 52	Expansion	Preliminary Engineering
Knightsville 66	Installation	Preliminary Engineering
Anthony 64	Expansion	Preliminary Engineering
Apponaug 3	Expansion	Preliminary Engineering
Drumrock	Expansion	Preliminary Engineering
Coventry	Expansion	Preliminary Engineering

Prepared by or under the supervision of: Jennifer L. Grimsley

PUC 2-8

Request:

Referencing the Volt/Var Management Project, please provide copy of the RFP, the number of bidders, and the review process for choosing UtiliData. Please explain what a statement of work entails separate from the specifications in the RFP. Please explain the components of the $1.2 million budget. (p. 64)

Response:

The Request for Proposal ("RFP") was submitted to seven vendors, each of which had varying approaches for volt/var optimization. Five of the seven vendors submitted bids. The RFP is attached to this response as Attachment PUC 2-8.

Prior to receiving the responses, an evaluation scorecard was drafted to assess each vendor's response to the RFP. Key elements of the RFP were weighted and the responses were scored by the Company's engineering team. The technical evaluation was done independently from the cost evaluation. Costs were not supplied to the engineering team while evaluating the technical merits. After completing the technical evaluation, cost rankings were included in the scorecard and the rankings were re-calculated. The top ranked two vendors were given an opportunity to provide final pricing and then re-ranked. Finally, the highest ranking vendor was then selected.

The Statement of Work ("SOW") is a document signed by the parties which defines their commitment to perform specific tasks and provides a defined set of deliverables based on stated assumptions, Terms and Conditions, project plans, and financial commitments. The final version of the SOW, which was signed by both National Grid and Utilidata, is attached to this response as Attachment PUC 2-8. Pursuant to Commission Rule 1.2 (g), the Company is seeking confidential treatment of Attachment PUC 2-8 and is providing the PUC with one (1) copy of the confidential version of this attachment.

The ISR included a proposed $1.2 million budget for FY15 (based on a total budget of $2.5 million) for implementing an advanced volt/var solution. Work in FY15 will include progress payments to Utilidata, design, engineering, and material procurement for the distribution line and substation components, including radio communications, and the start of construction for the distribution line and substation components. The costs for the Utilidata control scheme are included in the distribution line component and have not increased from the stated vendor costs in the Company's original estimate.

PUC 2-8, page 2

Since the submission of the ISR, the Company has begun preliminary engineering, and it has been determined that an additional Information Services component is needed for this project to establish secure connectivity between field devices, the AdaptiVolt core unit (provided by Utilidata), and the National Grid Energy Management System. The Company is currently drafting an RFP to refine the necessary scope and estimate for this Information Services component, and will include any updates which impact the discretionary ISR budget in its ongoing quarterly updates.

nationalgrid

Utilidata
Statement of Work (SOW)
for
Volt/VAR Optimization Demonstration Project

To
National Grid
40 Sylvan Rd.

Waltham, MA
12/19/13

Table of Contents

1. Overview and Approach

1.1 National Grid's Smart Grid Demonstration Objectives

The Narragansett Electric Company, d/b/a National Grid is pursuing a Volt/VAR Optimization (VVO) Demonstration Project in the state of Rhode Island. National Grid has selected Utilidata to supply centralized control functionality designed to optimize the operation of existing/new reactive resources and voltage regulation devices on seven distribution feeders selected for the demonstration project. The benefits of distribution feeder reactive support and voltage regulation are well known and individual capacitor installation and voltage regulators can be justified for reasons of voltage improvements and/or capacity release. However, National Grid is in the process of embarking on Volt/VAR control systems and strategies using centralized control algorithms. National Grid's goal is to use such a project for the following reasons.

- Determine the potential operational benefits from these systems as stated by the Vendors that would improve service to customers;
- Understand potential synergies with other rapidly developing uses of advanced technology on power distribution systems and/or areas where these technologies may work in opposition to one another;
- Understand how application of these systems could be integrated with existing guidelines to meet current objectives for Volt/VAR infrastructure;
- Guide system planners on potential benefits from deployment including clear direction on justification of infrastructure development costs;
- Understand system performance when distribution system is out of normal configuration

1.2 Utilidata Approach

In response to the requirements stated in National Grid's Request for Proposal (RFP), Utilidata will provide the below-specified four major Volt/VAR Optimization services:

1. Overall VVO Solution Project Management - The National Grid's Project Manager (PM) will oversee the activities/progress of the entire project and the Utilidata PM will supervise the efforts of the Utilidata Deployment Team and coordinate these efforts with the National Grid's PM. During circuit infrastructure design and system development, the Utilidata PM will work closely with the National Grid's team to assist with design and installation questions/issues related to interoperability of the AdaptiVolt™ system with the National Grid's equipment and distribution management systems. Utilidata's AdaptiVolt™ application is a Volt/VAR Optimization solution that uses signal processing to inform auto-adaptive control algorithms. Throughout the project, the Utilidata PM will provide weekly progress reports to the National Grid PM in order to ensure the project is meeting all aspects of the projected timeline, cost and performance.
2. Engineering Consulting Services - Utilidata will work with the National Grid's Advanced Engineering department to provide in-depth VVO engineering expertise which includes engineering consulting services for the development of precise locations for feeder monitoring devices, configuration settings, communications, and National Grid training (installation, operation and maintenance). In addition, Utilidata will provide system-commissioning services to ensure a smooth start-up and hand-off to the National Grid's operators.
3. Equipment Solutions - Utilidata will provide the components listed in the Equipment and Hardware List Section to enable the AdaptiVolt™ VVO system to provide automatic control at National Grid's Tower Hill and Putnam Pike substations feeding the 88F1, 88F3, 88F5, 88F7, 38F1, 38F3 and 38F5 12.47 kV circuits. The AdaptiVolt™ Core Unit. All Utilidata-provided devices (see Section 1.4,1 Utilidata Scope of Work - Equipment) will be delivered pre-configured and ready for installation by the National Grid's installation teams. Prior to commissioning, Utilidata will provide installation supervision services in order to transfer VVO device installation best practices and lessons learned.
4. Measure and Verification (M&V) - Utilidata will provide M&V analysis services to support the assessment of the energy savings and other benefits realized by implementing the VVO system and will work with the National Grid on establishing the criteria for what analytical data will be needed throughout this project.

1.3 General Specification

This Specification describes the work to be undertaken by Utilidata under Equipment Purchase and Software License and Maintenance Agreement dated December, 2013 and executed by National Grid and Utilidata ("Services Agreement") and the terms and conditions contained herein.

To the extent there is any contradiction, inconsistency or ambiguity between the terms of this Statement of Work and the Agreement, **except where explicitly stated in bold and underlined to the contrary**, the Agreement will govern.

1.4 Project Scope

National Grid selected two separate geographic locations to perform this project which are Putnam Pike substation in northern RI and Tower Hill substation in southern RI. There are a total of seven 12.47kV distribution feeders, four (Tower Hill sub) receive supply voltage are regulation via a substation transformer equipped with a Load Tap Changer (LTC) and three (Putnam Pike sub) are equipped with individual phase feeder substation voltage regulators. Both of these distribution substations are supplied from 115kV transmission lines. Per the RFP, Putnam Pike substation work will be conducted by National Grid to gain supervisory control of the single-phase regulators.

In addition to the identified substation work, distribution line infrastructure development is required to address thermal voltage and/or reactive performance issues that have been identified by National Grid by a project study completed in August 2013. During the project study of existing system performance National Grid has modeled all seven 12.47kV distribution feeders using CYME distribution feeder analysis software. National Grid will perform this work in conjunction with the engineering associated with VVO project. All distribution feeders have existing three phase capacitors installed at various locations. Three-phase line regulators are also present on several of the feeders.

The specific scope of work of each party is outlined below in the following sections.

1.5 Utilidata Scope of Work

a. **Engineering Services**

Utilidata will deliver to the project engineering, design, configuration, assembly, testing and related equipment services required to implement the AdaptiVolt™ system at the above defined locations.

The engineering services will included::

- Coordination with National Grid to identify locations for the Utilidata provided Line Voltage Monitors
- Engineering/business support as needed for National Grid's planning engineers to identify cost/benefit analysis for proposed infrastructure and VVO system upgrades
- Integration and configuration assistance for National Grid based on VVO project best practices
- Field commissioning and start-up support for all Utilidata provided equipment

Engineering Deliverables

- GPS/pole location coordinates of proposed Line Voltage Monitor Locations
- DNP 3.0 profiles for all Utilidata provided equipment

b. **Equipment**

Refer to Appendix F for complete definition of all equipment, including software, hardware provided
.

c. **Services for Equipment Provided**

- Installation support, supervision and guidance for all Utilidata-provided equipment. Utilidata will provide detailed instructions for installation and power-up of all supplied equipment, as well as be available for on-site or phone support (as needed) during the installation.
- Integration support Utilidata will provide all necessary support for the integration of the AdaptiVolt™ system into National Grid's EMS system. This includes providing all data points available from the AdaptiVolt™ system and assisting with integration testing to confirm proper

functionality.Utilidata will provide integration support services to National Grid with any of their 3rd party vendors for the project.

d. **M&V Services**

- Analysis of all circuits included in project using Automated Conservation Voltage Reduction (CVR) Protocol #1 (Protocol")
- Utilidata will design the M&V analysis per requirements provided by National Grid on design and conduct of experiment, in accordance with methodologies outlined in the Protocol, including definition of reporting metrics

M&V Deliverables

- Final VVO Performance Report,(sample report in Appendix H) including, but not limited to, the following:
    - A full description of the analysis methods and procedures
    - Summary of conservation metrics including:
        - Voltage reductions
        - Energy consumption
        - CVR Factors
        - Graphical representation of the circuit performance
        - Files of raw data used for analysis in an mutually agreed upon format and delivery

1.6 Deliverables

a. **Documentation Deliverables**

a. Implementation Plan – Details of project schedule and additional information pertinent to the deployment process
b. Test Plan - Detailed process and criteria for testing the AdaptiVolt™ system. This includes testing throughout the entire configuration, integration and commissioning activities
c. Complete system points list – to be used for integration of AdaptiVolt™ into EMS system
d. System As-Built drawings: full set of mechanical/electrical drawings of Utilidata provided equipment.
e. Factory Acceptance (FAT) Test Approval Document – This document captures the results of the formal lab test performed prior to the deployment of the system to the field, as well as any applicable action items resulting from the test
f. Commissioning Acceptance Test Approval Document – This is the document used to signify the completion of deployment and National Grid's acceptance of the system installation and operation.
g. Input to and work with National Grid to complete the Software Delivery Process (SDP) documents as referenced in Appendix A.
h. Training documents reviewed and approval by National Grid

b. **Utilidata Deliverables**

- Factory Acceptance Test and Approval
- Commissioning Acceptance Test and Approval
- SDP documents signoff
- All Documentation deliverables as noted in 1.6.a
- Successful completion of training session

1.7 National Grid Scope of Work

National Grid will deliver to the project the following activities and services.

a. **Engineering Services**

- Safety Training for all Utilidata employees as required by the National Grid for on-site access and labor
- Engineering design of feeder structure, including placement of capacitor and voltage regulator assets
- Engineering design of the selected communications network

- Configuration of all National Grid provided field devices, including (but not limited to): meters, Remote Terminal Unit (RTU), capacitor bank controls, voltage regulator controls, on-load tap changer controls, and communications devices
- Testing of all National Grid-provided communication networks prior to commissioning and start-up of the Utilidata-provided AdaptiVolt™ system
- Integration of the AdaptiVolt™ system into EMS/SCADA

Engineering Deliverables

- DNP 3.0 profiles for all National Grid-provided equipment and systems
- DNP and IP addresses for all equipment associated with this project. This includes, but is not limited to all Station, Line and Telecomm equipment, plus the Utilidata supplied Core Unit and LVM
- Configuration setting for all National Grid-provided equipment (as available)
- Asset topology connectivity for all control elements (e.g. capacitor banks and voltage regulators, etc.) included in the project

b. **Equipment**

- Two (2) RTU DNP 3.0 capable for communication with all substation located devices. These RTUs may also serve as data concentrators for field devices serviced by their respective substations
    - Existing RTUs may be suitable for this purpose, provided they have appropriate communications and memory availability
- Communication modems, media and network connectivity for all National Grid and Utilidata-provided equipment, including field, substation and backhaul networks
- Thirty-nine(39) metering class potential transformers for use with the Utilidata-provided Line Voltage Monitors, including mounting brackets and all installation accessories
- All capacitor banks and DNP 3.0 capable controls required for this project
- All voltage regulators and DNP 3.0 capable controls required for this project
- All on-load tap changers and DNP 3.0 capable controls required for this project
- All Potential Transformers (PT), Current Transformers (CT) and DNP 3.0 capable meters for each circuit, as required for this project
- Power for all Utilidata-provided equipment (to be specified in project scoping document)

c. **Process for Utilidata Equipment Provisioning**

National Grid will install all equipment on its system which includes Utilidata provided equipment. For the AdaptiVolt Core Unit the following process will be followed:

- Utilidata will notify National Grid that the Core Unit will has been assembled and is ready for Factory Acceptance Test (FAT)
- National Grid will be present at Utilidata's factory while a FAT is completed
- Upon completion of the FAT the Core Unit will be shipped to a location (location to be determined) where National Grid will connect the AdaptiVolt Core Unit to its system with Utilidata present.
- Utilidata will verify that the Core Unit is functioning and follow the commissioning process as stated previously before National Grid accepts delivery of unit.

d. **M&V Services**

- Coordination with Utilidata on conduct of experiment, in accordance with methodologies outlined in Automated CVR Protocol #1 (the "Protocol") including definition of reporting metrics.
- Operation of the AdaptiVolt™ system in accordance with the defined M&V experiment

M&V Deliverables

- Raw data files for AdaptiVolt™ system operation to Utilidata for analysis purposes

1.8 Key Assumptions

This Statement of Work and Utilidata's efforts are based on the following key assumptions. Deviations that arise during the proposed program will be managed through an agreed upon Change Management procedure, and may result in adjustments to the project scope, estimated schedule, charges and other terms.

a. If Utilidata becomes aware of any issue that may affect the project (schedule, scope, staffing, delivery or cost), Utilidata will immediately notify National Grid in writing. Utilidata will work with National Grid to assess the issue and recommend approaches to address any issues.

b. Utilidata will be responsible for on-boarding their personnel to the program. National Grid standard background checks will be required for property access. The security badge and background check documents (Appendix E) should be completed by Utilidata sent to Brian Lanciault (Brian.Lanciault@nationalgrid.com) at National Grid's Procurement Department.

c. Utilidata will provide the services under this Statement of Work during normal business hours, 8:00 AM to 6:00 PM Eastern Time, Monday through Friday, except national holidays. Utilidata resources will be on site at National Grid as required.

d. Utilidata team leaders will provide weekly work plan updates, including percent completed, hours consumed, and estimated completion dates.

e. If a Storm Event is called by National Grid, stated timelines in this Statement of Work and the integrated project plan may be subject to delay. Utilidata and National Grid will work collaboratively to minimize impact to project schedule and budget.

f. All individuals from Utilidata that are not a USA citizen therefore under a visa situation will not be assigned to this project unless they have more than 18 months left on their visa period.

g. Utilidata will be responsible for ensuring the security and privacy of National Grid's customer information.

h. Utilidata will disclose to National Grid any third party product imbedded in their solution.

i. Appendix G has the data points which will be used for the project. These point may change at the discretion of National Grid

j. Appendix J represents the Utilidata Process flows

(1) AdaptiVolt Normal OP

(2) EMS Integration

(3) HMI Commands

1.9 Project Management

Designated Project Manager.(reference table in 1.15) Each party shall appoint a single point of contact (each, a "Designated Project Manager") to (a) receive communications and materials from the other party and (b) provide formal approval and/or acceptance with respect to services and deliverables (as applicable). Each Designated Project Manager shall: (i) be available to the other party during normal business hours via telephone and email; (ii) respond to the other party's inquiries (whether by telephone, email, or otherwise) within one (1) business day from the time of such inquiry; and (iii) be sufficiently authorized to make binding decisions and take the actions required under this Statement of Work. Each party may change its Designated Project Manager from time-to-time by written notification to the other party of such change.

1.10 Deliverable Materials Acceptance Procedure

Each deliverable as defined in the specification will be supplied by Utilidata to National Grid and reviewed and accepted in accordance with the following procedure:

a. An electronic version of the documented deliverable will be submitted to National Grid as a first draft for review.

b. Within five (5) business days of receipt, National Grid will provide Utilidata a list of requested revisions or a request for more time for review. If Utilidata receives no response from National Grid within five (5) business days, Utilidata will submit the deliverable for final review.

c. Utilidata will review the requested revisions with National Grid and provides a complete "no known issues" draft within two (2) additional days

d. Within three (3) business days of receipt, National Grid will accept the deliverable or provide Utilidata a written list of requested revisions. If Utilidata receives no response from the National Grid within three (3) business days, then the deliverable will be deemed accepted.
e. Utilidata provides the final draft for sign-off within two (2) additional business days

1.11 Completion Criteria

Utilidata will have fulfilled its obligations under this Statement of Work when all required deliverables have been achieved and a sign-off submitted to National Grid for approval.

1.12 Change Management Process

The SDP change management documents and tracks the necessary information required to effectively manage project change from project inception to delivery. The process establishes an orderly and effective procedure for tracking the submission, coordination, review, evaluation, categorization, and approval for release of all changes to the Project's baselines.

Utilidata is required to follow the National Grid Change Management Process identified in the National Grid SDP documents (Appendix A).

1.13 Software Products

List of the software, product and version used in the project. Utilidata will be responsible for supplying any and all software licenses

Software Product	Definition	Version of the Software
AdaptiVolt Core	Utilidata VVO solution	V1.5
RTU	GE D20	SAB6349-07
OIT PC	Operator interface terminal PC	Windows 7

1.14 Financials

A list of the devices, professional services and maintenance cost costs should be identified below. They should reflect your quotation.
National Grid will only commit to, call off and pay for devices, and professional service which we require and consume. Devices and associated prices should be unitized.

1.14.1 Cost Summary

The table below is a summary of all the cost for the project. This is further defined in Section 1.13.2 (Equipments); and Section 1.13.2 (Professional Services)

SUMMARY TABLE

Description	Total Cost	Comment
Equipment	[redacted]	Includes AdaptiVolt Core Unit, Line Voltage Monitors, Temperature Probe and Acromag Module
Professional Services		Includes Solution Project Management, Engineering Consulting Services, and Measure & Verification (M&V)
TOTAL		

1.14.2 Equipment

Utilidata shall provide National Grid with the devices listed in Appendix F, The table below is a summary of the equipment.. Utilidata will separately hold 3% of their pilot hardware quantities as strategic replacement hardware spares specifically quarantined for the 2012 Pilot.

Item Description/	Qty	Cost	Description	Lead Time	Estimated Delivery Date	Warranty Period
AdaptiVolt™ Core Unit	1	[redacted]	VVO system in 19" server rack	3 weeks	Depends On Integrated Plan	12 months from Utilidata/NG Factory Acceptance
Line Voltage Monitor	15		Pole mount box used to capture end of line voltage	4 weeks	Depends On Integrated Plan	12 months from Utilidata/NG Factory Acceptance
Temperature Probe	2	Part of the AdaptiVolt cost	Remote temperature sensor to gather substation ambient temperature	4 weeks	Depends On Integrated Plan	12 months from Utilidata/NG Factory Acceptance
Acromag Module	2	Part of the AdaptiVolt cost	Converts Temperature data into Modbus signals	4 weeks	Depends On Integrated Plan	12 months from Utilidata/NG Factory Acceptance
TOTAL		[redacted]				

1.14.3 Professional Services

Utilidata shall provide National Grid with the following Professional Services necessary to implement their solution as defined in this Statement of Work. When invoices are created for professional services, they will be required to meet the format defined in Appendix C. The information on the invoices should contain detailed information by resource, including date, tasks worked on, and activities accomplished.

Professional Services

The table below defines the cost of services for this project

Description	Agreed Maximum Cost
Project Management	[redacted]
Engineering Consulting Services	
Measurement and Verification	
TOTAL	

National Grid needs to ensure Utilidata is incentivized to do their portion of the project. We propose an invoice holdback mechanism that consists of 2 parts. As value added services are expended and / or products are supplied, they will be invoiced to National Grid at 70% of the value. The balance will be invoiced as follows

- Twenty percent (20%) of accumulated invoice value will only be invoiced when phased milestone (see below for Payment chart) / deliverables are successfully completed.
- Ten percent (10%) of all accumulated invoice value will only be invoiced once all solution implementation deliverables have been successfully completed.

Phased Milestones

Phased Milestones Phased Deliverables	
Phased Milestones	Percentage
Factory Testing Successfully Completed & Equipment Delivered to National Grid	80%
System Go live completed (System Commissioned, User Acceptance test completed, SDP and documentation delivered	10%
M&V study completed and final report accepted to National Grid	10%

1.14.4 Professional Services Fee Schedule

Below are the functional hourly rates for professional services resources;

FEE SCHEDULE

CLASSIFICATION	BASE RATE
Consulting Electrical Engineering	[redacted]
Project Manager	
Principal Engineer	
Control Engineer	
Design & Drafting	
Panel Fabrication	
Clerical & Documentation	
Phone Tech Support	

REGULAR TIME	Monday – Friday between 7 AM EST – 6 PM EST and up to 8 hours	BASE RATE
OVERTIME	Monday – Friday before 7 AM EST, after 6 PM EST and/or more than 8 hours combined work and travel Saturday up to 8 hours combined work and travel	BASE RATE X [redacted]
PREMIUM TIME	Saturday more than 8 hours combined work and travel	BASE RATE X [redacted]
HOLIDAYS	Sunday, New Year's Day, Memorial Day, Independence Day, Thanksgiving Day, Thanksgiving Friday, Christmas Day	BASE RATE X [redacted]
TRAVEL TIME	Time en-route from the Utilidata office in Providence to and from the job site	BASE RATE
STANDBY TIME	Time when the service person is standing by for work	PREVAILING RATE
HOLDOVER TIME	Time charged to retain a service person in the job site area in lieu of incurring additional expense by returning to Providence. Infers no standby or service rendered. Maximum amount charged will be 8 hours per day on weekdays and 4 hours per day on weekends.	PREVAILING RATE

TECH SUPPORT	Utilidata "Non-Warranty" technical support via telephone or direct modem connection. Minimum charge of [redacted] per call. Time invoiced to the nearest 15-minute increment.	[redacted]
MATERIALS	On T&M projects, Utilidata will apply a markup on Utilidata provided material as noted.	
	DIRECT EXPENSE REIMBURSEMENTS	
TRAVEL	Company or personal auto Other transportation Lodging Meals	
OTHER	Any non-service item (shipping, documentation, ETC	
TERM	Invoiced amounts are due on receipt and are considered past due after 30 days from date of invoice. Utilidata will charge 1 ½ % per month on past due amounts	

1.14.5 Maintenance Agreement

The first year of the maintenance agreement cost will be at no cost to Narragansett Electric.
Utilidata maintenance agreement (after the first year) will be [redacted]% of the software and hardware component of any applicable project (as defined in the appropriate SOW). Escalation on an annual basis will not exceed the annual increase in the Consumer Price Index.
In the case of the current VVO project with Narragansett Electric, the maintenance fee would be [redacted]% of the Equipment Solutions component of our pricing provided in the RFP. This category totals [redacted] so the annual maintenance fee (beginning in year two) would be [redacted]
Appendix I reflects this agreement

1.15 Utilidata Project Plan and Milestone Chart

.

An integrated plan will created by National Grid for the entire program. The Utilidata plan will need to be integrated into the overall plan. The Utilidata plan may need to be modified based on the integrated plan. A draft of Utilidata's high-level Project Plan can be found in Appendix D. The plan in Appendix D represents Utilidata project plan for their portion of the program.

1.16 Project Suspension

National Grid may find it necessary to suspend activities on all or a portion of the project scope. A project suspension will be handled as follows:

- National Grid will immediately notify Utilidata, and will follow-up with a written Change Order suspending activities within 3 business days.
- Utilidata will roll team members off and reduce its services charges to zero within a maximum of two weeks of official notification by National Grid.
- When the project resumes, Utilidata will provide commercially reasonable efforts to return the same team members in a timely manner.

1.17 Software Change

Should a change be required to the software version Utilidata will be required to formally contact National Grid so the change request can be reviewed and qualified.

- Emergency Patch/Release - Utilidata technical support team will contact National Grid operations team and advise them of the patch. National Grid ops team will schedule appropriate time for patching.

- Scheduled Release - Utilidata Product Management will issue Product Bulletin, along with appropriate documentation to National Grid. National Grid operations team may then schedule upgrade of the software at an appropriate time.

1.18 Training

Utilidata will provide 8 hours of National Grid training to personnel designated by National Grid. Training to include:

- AdaptiVolt™ Internal Operation - basic principles behind VVO operation and DSP
- Console Operator Terminal
- Integration to National Grid EMS system (as required by National Grid)
- Additional topics as needed by National Grid: Hands On/Hands Off mode, M&V
- Documentation manuals
- Video
- Unlimited personnel

1.19 Project Resourcing and Organization Chart

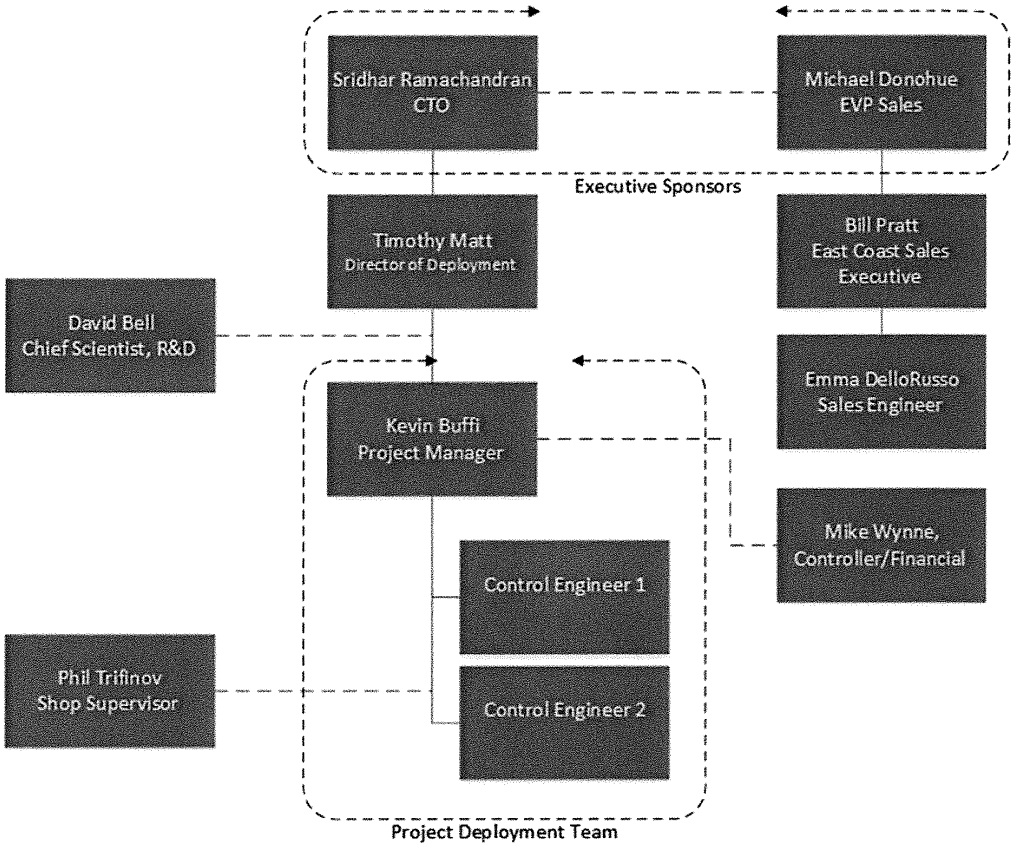
Utilidata personnel to be utilized on the project are subject to National Grid approval. National Grid reserves the right to request the replacement of any personnel. In the event Utilidata needs to change a resource on a project, National Grid will review and approve the proposed change with Utilidata Project Manager.

The following roles and responsibilities apply to the Project:

Project Resource Roles	Utilidata Resource	National Grid Resource
Lead Project Engineer	Patrick Fam	Tony Lasa
Project Manager	Kevin Buffi	John Skrzypczak
IS Project Manager	Phil Trifonov	Chandra Dikshith
Communications Engineer	Phil Trifonov	Mike Maljanian
Security	Marcel Andry-Bourgeois	Muks Ravipaty
Smart Grid Consultant	Jeremy Wilson	Ron Diorio
Procurement	Phil Trifonov	Brian Lanciault

Project

Below is shown **Utilidata** Organization Chart for the Project:


Sridhar Ramachandran
CTO
Michael Donohue
EVP Sales
Executive Sponsors
Timothy Matt
Director of Deployment
Bill Pratt
East Coast Sales
Executive
David Bell
Chief Scientist, R&D
Emma DelloRusso
Sales Engineer
Kevin Buffi
Project Manager
Mike Wynne,
Controller/Financial
Control Engineer 1
Phil Trifinov
Shop Supervisor
Control Engineer 2
Project Deployment Team

1.20 Key Staff

The organization chart in this section represents the planned roles to be staffed in execution of this Statement of Work. Additional roles may be added in the course of executing the tasks described in this Statement of Work within the limits of the Statement of Work, or though project change requests. A sub-set of these roles will be designated as Key Staff, and thus removal of these individuals from the project by Utilidata will be subject to the Key Staff provision, in the Agreement. Updates to Key Staff will be identified within 30 days of project kick-off.

The following Utilidata individuals/roles are identified as Key Staff:

Name	Role	Hourly Bill rate	Start Date	End Date
Kevin Buffi	Project Manager	Reference Section 1.14.4	Based On Integrated Project Plan	Based On Integrated Project Plan
Patrick Fam	Control Engineer	Reference Section 1.14.4	Based On Integrated Project Plan	Based On Integrated Project Plan
Bill Pratt	Account Manager	Reference Section 1.14.4	Based On Integrated Project Plan	Based On Integrated Project Plan

Appendix A: Solutions Delivery Process (SDP) Guidelines and Deliverables

This Appendix includes attached documents labeled SDP Overview and Guidance.doc. This document provides an overview of National Grid's PMO processes and procedures. The Technology Vendor agrees to follow the processes and procedures outlined in this document.

(Note: The compressed folder below includes templates of the SDP documentation. The Technical Vendors are responsible for working with National Grid to complete required SDP documentation).

NG SDP Overview

CompressedFolder

Mandate	Start-Up	Requirements	Design	Development	Implementation
Standard Deliverables for MEDIUM Impact Project					
Mandate	Investment Proposal Service Definition A Lessons Learnt Sanction Point Stage Gate	Business Requirments Technical Requirements Risk/Issues Log Project Initiation Document Conceptual Technical Model	Investment Proposal Total Cost of Ownership Model Logical Technical Model Physical Technical Model Functional Design Document Detailed Applications Design Document Testing Plan Saction Point Stage Gate	Building Specifications Deployment Plan Disaster Recovery Plan System Test User Acceptance Testing Operations Acceptance Test Problem Log Stage Gate	Authorisations to Move Solution into Production Service Transition Handover Document Post-Investment Plan Client Survey Investment Closure Report
As Required Deliverables					
Project Estimating Tool		Project Stakeholder Communications Resource Plan* Project Plan*	Training Plan Data Archtecture Model*	Decommissioning Plan* Service Level Agreement	Operationsl Level Agreement

* *Normally contained within other deliverables*

Appendix B: Security Requirements

For the 2012 Pilot, National Grid will require its vendors to comply with NERC guidelines, the ISO Information Security Management Standard (ISMS), and the National Grid Global Information Security Polices (see attachments below).

Under the National Grid Global Information Security Policies, vendors will be subject to periodic assessments to confirm that they are logging events, logs are reviewed, unusual events are reported and addressed, and continuous monitoring is engaged. The National Grid will also require their compliance with security certification, security awareness training, and their full cooperation in the investigation of any "exception" that is the result of and intrusion ensuring that they provide us with the forensic tools to successfully identify and categorize any threats or vulnerabilities.

NG Consolidated Security Controls

IS Security Framework for RI WC

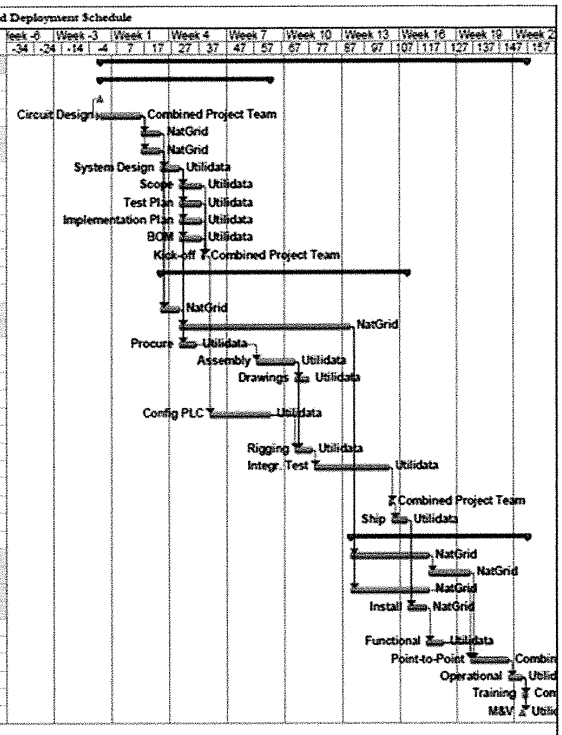
Appendix C: Invoicing Guidance

Invoicing Guidance - Utilidata

Appendix D: Utilidata Project Plan

Utilidata Proposed Deployment Schedule

ID	Task Name	Duration	Resource Names
1	**Project Time Line**	**105 days**	
2	**Stage 1 - Discovery/Definition**	**41 days**	
3	Project Begin Date	0 days	
4	Complete Circuit Engineering: Define Final Design	10 days	Combined Project Team
5	Define Telecom Plan	5 days	NatGrid
6	Identify Line/Station Equipment Requirements	5 days	NatGrid
7	Finalize AdaptiVolt™ Design/Configuration	5 days	Utilidata
8	Develop/Deliver Project Scope Document	5 days	Utilidata
9	Develop/Deliver Test Plan Document	5 days	Utilidata
10	Develop/Deliver Implementation Plan	5 days	Utilidata
11	Create Final Bill-of-Materials	5 days	Utilidata
12	Kick-off Meeting	1 day	Combined Project Team
13	**Stage 2 - Configuration/Bench Test**	**59 days**	
14	**Hardware**	**45 days**	
15	Order Telecom/Line/Station Equipment	5 days	NatGrid
16	Equipment Lead Time	8 wks	NatGrid
17	Order System Components	3 days	Utilidata
18	Assemble/Test System	10 days	Utilidata
19	Complete "As-Built" Drawings	3 days	Utilidata
20	**Software**	**15 days**	
21	Configure AdaptiVolt™ System	15 days	Utilidata
22	**Integration**	**21 days**	
23	Rig System for Lab Simulation Testing	4 days	Utilidata
24	Test Fully Integrated System	17 days	Utilidata
25	**Factory Acceptance Test**	**5 days**	
26	Conduct FAT	1 day	Combined Project Team
27	Ship System to Site	4 days	Utilidata
28	**Stage 3 - Commission**	**45 days**	
29	Install Telecom Equipment	4 wks	NatGrid
30	Test Telecom System	2 wks	NatGrid
31	Install Line/Station Equipment	4 wks	NatGrid
32	Install AdaptiVolt™ System in Field	1 wk	NatGrid
33	**System Acceptance Testing**	**24 days**	
34	Power-up/Functional Test (on-site)	4 days	Utilidata
35	Point-to-Point Testing (From Office)	10 days	Combined Project Team
36	Full Operational Test (on-site)	3 days	Utilidata
37	Training / Hand-off (on-site)	2 days	Combined Project Team
38	M&V	0 days	Utilidata



Appendix E: Security Badge and Background Check Documents


Contractors Desk Guide


ID Badge form


BAckground Information


Attachment B-2

Appendix F: Equipment List – National Grid & Utilidata

NG = National Grid
U = Utilidata

National Grid Provided Equipment List

Device	Location	Comms (WiMax or Cell)	Configuration	Installation	Commissioning	Notes
Load Tap Changer	Tower Hill Substation	N/A	NG	NG	NG	Tower Hill Transformer #1 LTC.
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F1 A ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F1 B ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F1 C ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F3 A ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F3 B ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F3 C ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F5 A ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F5 B ph Regulator
Single Phase Substation Voltage Regulators	Putnam Pike Substation	N/A	NG	NG	NG	Putnam Pike 38F5 C ph Regulator
Three Phase Capacitor Bank	P160 PUTNAM PIKE	WiMax	NG	NG	NG	
Three Phase Capacitor Bank	P15 AUSTIN AVE	WiMax	NG	NG	NG	
Three Phase Capacitor Bank	P194 PUTNAM PIKE	WiMax	NG	NG	NG	
Three Phase Capacitor	P12 PUTNAM PIKE	WiMax	NG	NG	NG	

Bank					
Three Phase Capacitor Bank	P47 PUTNAM PIKE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P80 SNAKEHILL RD	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P92 COOPER RD	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P89 PUTNAM PIKE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P62 MAPLEVILLE RD	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P140 PUTNAM PIKE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P317 GREENVILLE AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P277 GREENVILLE AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P133H ATWOOD AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P132-2 ATWOOD AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P66 GREENVILLE AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P342 GREENVILLE AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P379 GREENVILLE AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P41 SMITH AVE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P76 WEST GREENVILLE RD	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P41 WEST GREENVILLE RD	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P26 DANIELSON PIKE	WiMax	NG	NG	NG
Three Phase Capacitor Bank	P25 WEST ALLENTON RD	Cell	NG	NG	NG
Three Phase Capacitor Bank	P16 INDIAN CORNER	Cell	NG	NG	NG
Three Phase Capacitor Bank	P3 SLOCUM	Cell	NG	NG	NG
Three Phase Capacitor Bank	P36 MAIN ST	Cell	NG	NG	NG
Three Phase Capacitor Bank	P17 SOUTH COUNTY TRAIL	Cell	NG	NG	NG
Three Phase Capacitor Bank	P64 SOUTH COUNTY TRAIL	Cell	NG	NG	NG
Three Phase Capacitor Bank	P34 SOUTH COUNTY TRAIL	Cell	NG	NG	NG
Three Phase Capacitor Bank	P168 TOWER HILL RD	Cell	NG	NG	NG
Three Phase Capacitor Bank	P225 TOWER HILL RD	Cell	NG	NG	NG
Three Phase Capacitor Bank	P21 BRIDGETOWN	Cell	NG	NG	NG
Three Phase Capacitor Bank	P67 TOWER HILL RD	Cell	NG	NG	NG
Three Phase Capacitor Bank	P147 BOSTON NECK	Cell	NG	NG	NG
Three Phase Capacitor	P182 BOSTON NECK	Cell	NG	NG	NG

Bank					
Three Phase Capacitor Bank	P28 SOUTH FERRY	Cell	NG	NG	NG
Three Phase Capacitor Bank	P9 SOUTH FERRY	Cell	NG	NG	NG
Three Phase Capacitor Bank	P14 BOSTON NECK	Cell	NG	NG	NG
Three Phase Capacitor Bank	P1H FAIRWAY	Cell	NG	NG	NG
Three Phase Capacitor Bank	P24 OAK HILL	Cell	NG	NG	NG
Three Phase Capacitor Bank	P47 ANNAQUATUCKET	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P110 SAW MILL A PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P110 SAW MILL B PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P110 SAW MILL C PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P45 PUTNAM PIKE A PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P45 PUTNAM PIKE B PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P45 PUTNAM PIKE C PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P6 COOPER RD A PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P6 COOPER RD B PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P176 ATWOOD AVE A PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P176 ATWOOD AVE B PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P176 ATWOOD AVE C PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P273 EAST RD A PH REGULATOR	WiMax	NG	NG	NG
Single Phase Distribution Line Regulators	P43 EXETER A PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P43 EXETER B PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P43 EXETER C PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line	P9 RAILROAD A PH REGULATOR	Cell	NG	NG	NG

Regulators					
Single Phase Distribution Line Regulators	P9 RAILROAD B PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P9 RAILROAD C PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P26 TOWER HILL A PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P27 TOWER HILL B PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P28 TOWER HILL C PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P131 BOSTON NECK RD A PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P131 BOSTON NECK RD B PH REGULATOR	Cell	NG	NG	NG
Single Phase Distribution Line Regulators	P131 BOSTON NECK RD C PH REGULATOR	Cell	NG	NG	NG

Utilidata Provided Equipment List
NG = National Grid
U = Utilidata

Utilidata Purchased Equipment

Item	Device	Make	Model	Location	Commissioning	Power Requirements	Configuration	Installation	Commissioning	Notes
1	AdaptiVolt Core Unit	Utilidata Design		Northboro	U	120vac	U	NG	U	This unit includes the following Items 2-4
2	PLC	Allen Bradley		(Part of #1: AdaptiVolt™ Core unit)		120vac (supplied by Core Unit)				
3	RTU	GE	D20MX	(Part of #1: AdaptiVolt™ Core unit)		120vac (supplied by Core Unit)				discuss other possible options
4	Computer/Memory	Custom	Win7 32-bit, 4GB RAM	(Part of #1: AdaptiVolt™ Core unit)		120vac (supplied by Core Unit)				
5	Line Voltage Monitor 1	Utilidata Design	304	Tower Hill 88F1 P58 Slocum Rd	U	120vac	U	NG	U	These locations were determined from National Grid Study
6	Line Voltage Monitor 2	Utilidata Design	304	Tower Hill 88F1 P8h Railroad Ave	U	120vac	U	NG	U	These locations were determined from National Grid Study
7	Line Voltage Monitor 3	Utilidata Design	304	Tower Hill 88F3 P123 Tower Hill	U	120vac	U	NG	U	These locations were determined from National Grid Study
8	Line Voltage Monitor 4	Utilidata Design	304	Tower Hill 88F3 P22 Tower Hill	U	120vac	U	NG	U	These locations were determined from National Grid Study
9	Line Voltage Monitor 5	Utilidata Design	304	Tower Hill 88F5 P128 Boston Neck Rd	U	120vac	U	NG	U	These locations were determined from National Grid Study
10	Line Voltage Monitor 6	Utilidata Design	304	Tower Hill 88F5 P31 Boston Neck Rd	U	120vac	U	NG	U	These locations were determined from National Grid Study
11	Line Voltage Monitor 7	Utilidata Design	304	Tower Hill 88F7 P194 Post Rd	U	120vac	U	NG	U	These locations were determined from National Grid Study

12	Line Voltage Monitor 8	Utilidata Design	304	Putnam Pike 38F1 P30 Putnam Pike	U	120vac	U	NG	U	These locations were determined from National Grid Study
13	Line Voltage Monitor 9	Utilidata Design	304	Putnam Pike 38F1 P181 Snake Hill Rd	U	120vac	U	NG	U	These locations were determined from National Grid Study
14	Line Voltage Monitor 10	Utilidata Design	304	Putnam Pike 38F3 P3 Cherry Hill Rd	U	120vac	U	NG	U	These locations were determined from National Grid Study
15	Line Voltage Monitor 11	Utilidata Design	304	Putnam Pike 38F3 P113 Greenville Ave	U	120vac	U	NG	U	These locations were determined from National Grid Study
16	Line Voltage Monitor 12	Utilidata Design	304	Putnam Pike 38F5 P46 Danielson Pike	U	120vac	U	NG	U	These locations were determined from National Grid Study
17	Line Voltage Monitor 13	Utilidata Design	304	Putnam Pike 38F5 P52 West Greenville Ave	U	120vac	U	NG	U	These locations were determined from National Grid Study
18	Line Voltage Monitor 14	Utilidata Design	304	TBD	U	120vac	U	NG	U	TBD if needed after final study
19	Line Voltage Monitor 15	Utilidata Design	304	TBD	U	120vac	U	NG	U	TBD if needed after final study
20	Temperature Probe 1	Omega Engineering	RTD-870-100	Tower Hill Substation	U	N/A	n/a	NG	U	
21	Temperature Probe 2	Omega Engineering	RTD-870-100	Putnam Pike Substation	U	N/A	n/a	NG	U	
22	Acromag Module	Acromag	932MB-0900	Tower Hill Substation	U	24vdc	n/a	NG	U	
23	Acromag Module	Acromag	932MB-0900	Putnam Pike Substation	U	24vdc	n/a	NG	U	

Appendix G: Data Points

Data Points for VVO RI

Appendix H: Sample M&V Report


Sample M&V Report

Appendix I: Maintenance Agreement Letter

MAintenance
Agreement Letter

Appendix J: Process Flows


Utilidata AdaptiVolt Normal Op


Utilitdata EMS Intergration


Utilidta HMI Commands

PUC 2-9

Request:

How should the effectiveness of the cycle pruning be evaluated where tree related incidents are relatively constant, both by number and percentage, over the past six years, and seem to be rising in number? (p. 73)

Response:

The objective of cycle pruning is to remove tree growth and create a clearance between all vegetation and the electrical conductors. The clearance is a dimension from above, to the side, and below the primary conductors. The effectiveness of cycle pruning can be evaluated by examining the Company's reliability metrics, which show that incidents from tree growth-related interruptions made up of 50 of the 599 or 8% of tree-related events for the calendar year 2013. In addition, the number of customers affected by those same growth-related interruptions was 881 customers or 1.4% of the total customers interrupted by tree-related events. These metrics point to the success of the cycle pruning program especially as the Company has now completed one full four-year cycle on all circuits. It is expected that these metrics will continue to improve through a second cycle of circuit pruning.

The Company has reported through the Vegetation Management Cost Benefit Report that cycle pruning provides an average improvement of 28% in customers interrupted on circuits in the fiscal year following pruning. In addition, a 78% improvement can be expected on circuits where the Company performs hazard tree removal. The Company's hazard tree program has proven to have the greatest impact on reliability, but it has only been performed on 10% of the circuits in Rhode Island to date.

Additionally, it is important to note that cycle pruning not only improves reliability but also provides a measure of public and worker safety by minimizing the risk of climbable tree access to the facilities, limiting incidents from falling limbs, reducing the risk of wildfire from vegetation conductor contact, and improving access to the facility for the Company's line crews during routine maintenance as well as outage restoration events.

Lastly, there is a significant economic benefit to keeping the circuit pruning program on schedule as industry studies on deferred maintenance have shown cost increases of 25% and more for circuit pruning when allowed to go past the optimal cycle point where limbs are now growing up between the primary conductor phases due to safety risks for the tree worker.

Prepared by or under the supervision of: Ryan Moe

PUC 2-10

Request:

How was the 3% inflationary factor derived and why is it appropriate? (p. 76)

Response:

The Company derived the 3% inflationary factor by referencing the Bureau of Labor Statistics Consumer Price Index. While there are no exact numbers for utility vegetation management, there are suitable comparisons. The numbers from the December 2013 Consumer Price Index show:

Energy Service – 2.4% increase
Trash Collection – 2.9% increase
Construction – 4.8% increase

Given the range of these increases, the 3% increase used for vegetation management seems reasonable.

PUC 2-11

Request:

In Docket 4382, National Grid provided the Division with a table entitled EHTM Benefits Compared to Statewide Performance for FY 2008-FY2011. Please provide an updated table to include FY 2012.

Response:

The updated table is provided in Attachment PUC 2-11.

In an effort to normalize the data used to show the EHTM benefits, the Company compared state-wide, tree-related customer interruptions for the same years as shown in Attachment PUC 2-11. The EHTM data previously discussed is included for direct comparison. Noting the percent change column on the far right of the table, it clearly shows that the EHTM program provided statistically significant reliability benefits.

FY 2008

	Customer Interruptions					Customer Interruptions				
	FY 2005	FY 2006	FY 2007	3 Year AVG	Project Year	FY 2009	FY 2010	FY 2011	3 Year AVG	3 Year AVG Δ CI
EHTM Feeders	24,432	20,467	21,482	22,127		12,513	7,477	9,213	9,734	12,393
State-wide	70,678	135,209	104,439	103,442		80,224	86,133	97,122	87,826	15,616

FY 2009

	Customer Interruptions					Customer Interruptions				
	FY 2006	FY 2007	FY 2008	3 Year AVG	Project Year	FY 2010	FY 2011	FY 2012	3 Year AVG	3 Year AVG Δ CI
EHTM Feeders	34,306	25,909	36,060	32,092		6,548	9,013	15,972	10,511	21,581
State-wide	135,209	104,439	113,372	117,673		86,133	97,122	99,143	94,133	23,541

FY 2010

	Customer Interruptions					Customer Interruptions				
	FY 2007	FY 2008	FY 2009	3 Year AVG	Project Year	FY 2011	FY 2012	FY 2013	3 Year AVG	3 Year AVG Δ CI
EHTM Feeders	25,021	107,654	17,760	50,145		6,731	13,032	12,247	10,670	39,475
State-wide	104,439	113,372	80,224	99,345		97,122	99,143	99,571	98,612	733

FY 2011

	Customer Interruptions					Customer Interruptions				
	FY 2008	FY 2009	FY 2010	3 Year AVG	Project Year	FY 2012	FY 2013		2 Year AVG	2 Year AVG Δ CI
EHTM Feeders	553	2,809	34	1,132		186	425		306	827
State-wide	113,372	80,224	86,133	93,243		99,143	99,571		99,357	(6,114)

FY 2012

	Customer Interruptions					Customer Interruptions		
	FY 2009	FY 2010	FY 2011	3 Year AVG	Project Year	FY 2013		1 Year Total
EHTM Feeders	8,905	23,724	13,268	15,299		5,819		5,819
State-wide	80,224	86,133	97,122	87,826		99,571		99,571

	AVG Pre-Project	AVG 1st Year Post-Project	AVG 2nd Year Post-Project	AVG 3rd Year Post-Project
EHTM Feeders	24,159	6,359	7,487	12,477
State-wide	100,306	90,656	95,492	98,612

PUC 2-12

Request:

What is the rationale for focusing on the first year post-EHTM work for its effectiveness? (p. 78)

Response:

Due to tree growth, storms, disease, and infestation, the most reliable data will be in the year immediately following EHTM work. Given the variability that can be present in reliability datafrom year to year, however, the Company typically also looks at three-year averages for reliability based programs. The Company provides this data in its annual Vegetation Management Cost Benefit Reports.

Prepared by or under the supervision of: Ryan Moe

PUC 2-13

Request:

What is the criteria that will be used to assess the costs and benefits of the I&M program on an ongoing basis? (p. 86)

Response:

The Company has agreed to a cost benefit methodology as shown in Attachment PUC 2-13, which was established in Docket No. 4307 regarding the Company's2013 Electric Infrastructure, Safety and Reliability Plan. This attachment is taken from the Flood Mitigation Plan and Vegetation Management Program and Inspection and Maintenance Program ("I&M") Methodology as provided to the PUC on June 29, 2012.

Reports on the safety benefits as described in Attachment PUC 2-13 have not yet been provided in the quarterly updates. The Company will include these reports for the complete I&M program since its inception in FY11 in the next quarterly report to be issued for the third quarter of FY14.

2. **Inspection & Maintenance Program:** The Inspection and Maintenance Program is primarily a safety and asset condition program, not a targeted reliability program. Secondary benefits may be seen in reliability. The method for calculating the safety and reliability cost/benefit is as follows:
    a. Safety Benefits
        i. The Company will track and report the following in its quarterly updates:
            1. Number of Items Corrected
            2. Number of Items Remaining in the Backlog
            3. Number of Elevated Voltage Instances Corrected
    b. Reliability Cost Benefit
        i. The Company will quantify the reliability benefits for the Inspection and Maintenance Program on a fiscal year basis.
            1. The average number of Customers Interrupted (CI) for applicable cause codes (deterioration and lightning) during the three-year period prior to the project year will be used as a baseline
            2. The standard deviation for the baseline three-year average will be provided.
            3. The project year will be excluded from the analysis.
            4. Related CI will be calculated for the first full year post project, and additional years will be added as available.
            5. Benefits will be determined by comparing the pre-project related CI against the post-project related CI. Percent improvement by individual circuit, for the total annual work plan, and a running average percent improvement for all circuits completed in the program will be calculated.
            6. Costs by feeder will be used to calculate a cost per change in CI.
            7. This analysis will be provided each year in the August 1 Annual Reconciliation Filing.

National Grid's initial report on the reliability cost benefit and damage restoration cost benefit of the Vegetation Management program using the method described above will be for the FY2011 program, and will be provided in August 2012 with the Company's Annual Reconciliation Filing. National Grid's initial report on the reliability cost benefit of the Inspection & Maintenance program using the method described above will be for the FY2013 program, which is the first year of the program, and will be provided in August 2014 with the Company's Annual Reconciliation Filing. Reports on the Safety benefits for the Inspection & Maintenance program, as described above, will start with the FY2013 program, and will be provided in the FY2013 quarterly reports.

PUC 2-14

Request:

What is the criteria for tracking the results of underground I&M inspections in FY 2015? (p. 87).

Response:

As of the date of this response, the Company performs a hazard assessment upon entry to a manhole which is not documented. The Company is working towards tracking the results of the underground Inspection and Maintenance ("I&M") program following the criteria specified in the Electric Operating Procedure (EOP) NG-EOP UG006-Underground Inspection and Maintenance attached as Attachment PUC 2-14.

nationalgrid **ELECTRIC OPERATING PROCEDURES**	**Doc No.:** NG-USA EOP UG006 **Page:** Page 1 of 8 **Date:** 08/17/09
SUBJECT: Underground Inspection and Maintenance	**SECTION**: Underground

GENERAL INFORMATION:

The purpose of this procedure is to outline the requirements for the patrol and maintenance activities associated with National Grid's underground transmission and distribution facilities.
The variance in inspection procedures in New York, Massachusetts, New Hampshire, and Rhode Island service territories is due to the requirements of New York Public Service Order 04-M-0159 and the Massachusetts Department of Telecommunications and Energy recommendations of December 9 2005, which is incremental to National Grid in New York and Massachusetts.

This program is designed for the patrol and designated maintenance of underground facilities on a five year schedule. The Inspector will record all required maintenance on an approved National Grid database.

The underground distribution facility maintenance items identified through this patrol are separated into four priority levels 1, 2, 3, and 4. The problem codes identified default to the appropriate priority level. The default priority level can be adjusted by the individual performing the inspection based on actual field conditions. These priority Levels are defined as follows:

Level 1- An identified facility/component or tree condition that must be repaired/replaced within 1 week.

Level 2 - Identified facility/component condition that must be repaired/replaced within 1 year.

Level 3 – Identified facility/component condition that must be repaired/replaced within 3 years.

Level 4 – This priority category is to collect inventory information on actual field conditions to be used by Investment Strategy and Work Planning.

All Level 1 priority conditions identified in the field shall be called in by the Underground Inspector as follows:

1. Notification by location:
    a. New York: contact System Operations Dispatch 1-877-716-4996.
    b. Bay State West and North & Granite: Westboro Control Center 1-508-389-9032.
    c. Bay State South, and Ocean State: Lincoln Control Center 1-401-335-6075.

2. Detailed information provided to the regional notification location:
    a. Identify yourself as a Company Underground Inspector and your work reporting area.
    b. Details of the Level 1 Priority Condition:
        i. Problem found.
        ii. District, Circuit/Feeder No., Line No., Tax District and Manhole/vault No.
        iii. Street address and any additional information that would assist in finding the location of the problem.
        iv. If you are standing by or have secured the location.

APPLICABILITY:

This procedure applies to all personnel involved with or responsible for the inspection or maintenance of underground transmission and distribution facilities.

DEFINITIONS:

Desktop Computer: A personal computer that is connected to the National Grid network and used to download the Hand Held device and retrieve the information in the form of reports.

Elevated Equipment Voltage Test: An A.C. rms voltage difference between utility equipment and the earth, or to nearby grounded facilities that exceeds the highest perceptible voltage levels for humans.

Hand Held Computer: An electronic data recording device that is used in the field to create a record of conditions found.

Hand-Hole: An enclosure identified for use in underground systems, provided with an open or closed bottom, and sized to allow personnel to reach into, but not enter, for the purpose of installing, operating, or maintaining equipment or wiring or both.

Infrared Inspection: An inspection conducted to detect abnormal heating conditions associated with separable connectors. An infrared inspection is required before work begins in an enclosed space, enclosure, padmounted transformer or padmounted switchgear.

Inspector: A qualified worker who can identify deficiencies or non-standard construction conditions on National Grid facilities.

Manhole: An enclosure identified for use in underground systems, provided with an open or closed bottom, and sized to allow personnel to enter, for the purpose of installing, operating, or maintaining equipment or wiring or both.

Patrol: An assessment of National Grid facilities for the purpose of determining the condition of the facility and any associated components.

Secondary Splice Box: An enclosure identified for use in underground systems. A secondary splice box may be required where the customer's number of secondary cables exceeds the maximum allowed amount on the transformer.

Service Box: See Hand-hole

Submersible Equipment: Electric equipment such as transformers and switches that, are generally located within a Hand-hole, Manhole, or Vault.

URD: Underground Residential Distribution

UCD: Underground Commercial Distribution

Underground Distribution Facilities: Manholes, vaults, hand-holes and service boxes, padmounted equipment and the components and equipment contained in these structures. (See GENERAL INFORMATION above).

User: An individual who the program administrator has authorized to use the inspection reporting program.

Vault: An enclosure, above or below ground, which personnel may enter and which is used for the purpose of installing, operating, or maintaining equipment or wiring or both.

PROGRAM ADMINISTRATOR:

Distribution Engineering Services

SCOPE:

Underground Transmission and Distribution Facility Maintenance

I. Patrols
II. Equipment to be Inspected and Maintenance Codes
III. Maintenance database
IV. Maintenance Schedule
V. Completion of Maintenance Codes
VI. Responsibilities

I. PATROLS

1. New York

Inspection of underground equipment will be scheduled in such a manner that each underground facility will be examined once every five years. These patrols shall be completed by December 31st of the schedule year.

One-fifth of all underground utility components should be inspected each year. URD and UCD facilities shall be inspected on the existing overhead distribution circuit schedule. Additionally all riser poles are inspected in accordance with the Transmission and Distribution Overhead Inspection Programs, NG-USA EOP T007 and NG-USA EOP D004. Customer owned manholes and vaults that enclose National Grid equipment shall require the inspection of these National Grid facilities.

The Inspection group is responsible to create the patrol schedule for their respective Regions for the remainder of underground facilities. The Inspector uses a Windows based hand held computer to record region, district, employee ID, feeder number, structure ID number, GPS location, tax zone, line number, comments and maintenance problem codes. The Inspector while patrolling shall also complete the following maintenance codes if found deficient upon inspection: 602 – Handhole missing nomenclature, 617 – manhole missing nomenclature, 639 - network transformer- missing nomenclature, 660 – switchgear missing nomenclature, 681 – transformer missing nomenclature, and 707 – vaults improper nomenclature. The Inspector will input the code into the Windows based handheld as required, as well as completing the work unit in the handheld upon field completion while at the site. If the Inspector finds unmapped facilities from the information supplied from the Geographic Information System (GIS), refer to NG-USA EOP G011, Preparation and Distribution of Electric Facilities Records, for required procedure for corrections.

2. New Hampshire and Rhode Island

Inspection of designated underground equipment will be scheduled in such a manner that each designated Underground Facility will be examined once every five years. These patrols shall be completed by March 31h of the fiscal year.

One-fifth of all metallic handholes, padmount transformers and switchgear shall be inspected annually. The metallic handhole covers shall be opened for a visual inspection. An external visual inspection shall be completed on the padmount transformers and switchgear. Additionally all separable components in the

metallic handholes are to be inspected by infrared. Refer to NG-USA EOP UG001 for infrared procedure. A "Level 1 Priority" shall be assigned to a temperature gradient greater than 20º, although it is recognized that consideration must be taken as to whether a customer outage will occur at this time and the negative impact the outage could have on the customer. This may require scheduling an outage with the customer within one week to satisfy this requirement. A "Level 2 Priority" shall be assigned to a temperature gradient between 10º and 20º. A "Level 3 Priority" shall be assigned to a temperature gradient less than 10º. Additionally, an elevated equipment voltage test shall be completed at each location, refer to NG-USA EOP-G016.

A working inspection on underground facilities is required for all manholes, vaults, handholes, splice boxes, junction boxes, padmount transformers, switchgear and submersible equipment, each time a crew performs work at one of these facilities. The format for data collected shall follow this EOP. All separable components in these facilities are to be inspected by infrared. Additionally an elevated equipment voltage test shall be completed at each location, refer to NG-USA EOP-G016.

All transmission riser poles are inspected in accordance with the Transmission NG-USA EOP-T007.

The Inspection group is responsible to create the patrol schedule for their respective Regions for the designated underground facilities. The Inspector uses a hand held computer to record region, district, employee ID, feeder number, structure ID number, GPS location, line number, comments and maintenance problem codes. The Inspector, while patrolling or crew while inspecting, shall also complete the following maintenance codes if found deficient upon inspection, 602 – Handhole missing nomenclature, 617 – manhole missing nomenclature, 639 - network transformer- missing nomenclature, 660 – switchgear missing nomenclature, 681 – transformer missing nomenclature, and 707 – vaults improper nomenclature. The Inspector will input the code into the Windows based handheld as required, as well as completing the work unit in the handheld upon field completion while at the site. If the Inspector finds unmapped facilities from the information supplied from GIS, refer to NG-USA EOP G011, Preparation and Distribution of Electric Facilities Records, for required procedure for corrections. Crews performing working inspections are to follow the same protocol for inspections by using either a handheld data entry unit or paper inspection logs requiring data entry by clerical support.

3. Massachusetts

Inspection of designated underground equipment will be scheduled in such a manner that each designated Underground Facility will be examined once every five years. These patrols shall be completed by March 31 of the fiscal year.

One-fifth of all manholes, vaults, metallic handholes, padmount transformers and switchgear shall be inspected annually. The metallic handhole covers shall be opened for a visual inspection. Manholes and vaults shall be opened and entered for inspection. An external visual inspection shall be completed on the padmount transformers and switchgear. Additionally all separable components in the metallic handholes, manholes, and vaults are to be inspected by infrared. Refer to NG-USA EOP UG001 for infrared procedure. A "Level 1 Priority" shall be assigned to a temperature gradient greater than 20º, although it is recognized that consideration must be taken as to whether a customer outage will occur at this time and the negative impact the outage could have on the customer. This may require scheduling an outage with the customer within one week to satisfy this requirement. A "Level 2 Priority" shall be assigned to a temperature gradient between 10º and 20º. A "Level 3 Priority" shall be assigned to a temperature gradient less than 10º. Additionally, an elevated equipment voltage test shall be completed at each location, refer to NG-USA EOP-G016.

A working inspection on underground facilities is required for all manholes, vaults, splice boxes, junction boxes, padmount transformers, switchgear and submersible equipment, each time a crew performs work at one of these facilities. The format for data collected shall follow this EOP. All separable components in these facilities are to be inspected by infrared. Additionally an elevated equipment voltage test shall be completed at each location, refer to NG-USA EOP-G016.

All transmission riser poles are inspected in accordance with the Transmission NG-USA EOP-T007.

The Inspection group responsible to create the patrol schedule for their respective Regions for the designated underground facilities. The Inspector uses a hand held computer to record region, district, employee ID, feeder number, structure ID number, GPS location, line number, comments and maintenance problem codes. The Inspector, while patrolling or crew while inspecting, shall also complete the following maintenance codes if found deficient upon inspection, 602 – Handhole missing nomenclature, 617 – manhole missing nomenclature, 639 - network transformer- missing nomenclature, 660 – switchgear missing nomenclature, 681 – transformer missing nomenclature, and 707 – vaults improper nomenclature. The Inspector will input the code into the Windows based handheld as required, as well as completing the work unit in the handheld upon field completion while at the site. If the Inspector finds unmapped facilities from the information supplied from GIS, refer to NG-USA EOP G011, Preparation and Distribution of Electric Facilities Records, for required procedure for corrections. Crews performing working inspections are to follow the same protocol for inspections by using either a handheld data entry unit or paper inspection logs requiring data entry by clerical support.

II. EQUIPMENT TO BE INSPECTED AND MAINTENANCE CODES

This EOP requires the visual inspection of the following facilities as designated above for New York, New Hampshire, Rhodes Island or Massachusetts, which require opening, and may require pumping on some items to assure a proper inspection:

- Manholes
- Vaults
- Handholes – non-fiberglass
- Splice boxes – non-fiberglass
- Junction boxes – non-fiberglass
- Pad mount transformers
- Pad mount switchgears
- Submersible equipment
- Handholes – fiberglass do not require opening
- Splice boxes – fiberglass do not require opening
- Junction boxes – fiberglass do not require opening

.

Maintenance Codes are shown on the Underground Field Survey Worksheet (Table 1). The Underground Field Survey Worksheet can be used by the field to record maintenance items and is used for informational purposes only. The latest transmission maintenance codes are downloaded to the Hand Held Computer each time there is a change that affects the maintenance code table contained in the Underground Maintenance Database. Printed copies of the latest maintenance code tables may be obtained by running a report on the look up tables from the Underground Maintenance Database.

SUBJECT: Underground Inspection and Maintenance Doc. No.: NG-USA EOP UG 006
Date: 08/17/09

INSPECTION PROGRAM AND MAINTENANCE CODES
TABLE 1

UNDERGROUND FIELD SURVEY WORKSHEET		
DATE:	INSPECTOR NAME:	EMPLOYEE ID
DIVISION	DISTRICT	FEEDER:

TOWN:	STREET:	POLE, MANHOLE, VAULT #	SUFFIX #

Handhole		Manhole		Net Protect		Net XFMR's		Switchgear		Transformer			
Vault		Trench		Submersible		Pull Box		Other		Equipment #			

MANHOLES, HANDHOLES, VAULT STRUCTURES
Water (in hole) Yes No

EV Test Required: Yes No Voltage Action Taken: Repaired De-energized
EV Found Voltage: Yes No

Gas Monitor Readings		Alarm Setting
Lower Explosive Limit (LEL)		10% or above
Oxygen (0_2)		% below 19.5, above
Carbon Monoxide (CO)		33 ppm
Hydrogen Sulfide (H_2S)		10 ppm

GIS	P/Q
260 **4** (NR) GIS map doesn't match field	/
261 **4** (NR) GIs Pole/line numbering in error on GIS	/
262 **4** (NR) GIS equip/hardware missing in GIS	/
263 **4** (NR) GIS equip removed in field, remove from GIS	/
269 **4** (NR) GIS Other GPS/GIS Errors	/
HANDHOLES	
600 **2** (NR) Broken/damaged/unsecured	/
602 **P** (NR) Missing nomenclature	/
603 **1** (R) Secondary needs repair	/
604 **4** (NR) Other (use comments)	/
MANHOLE	
610 **2** (NR) Ground rods missing	/
611 **2** (R) Cable/Joint leaking	/
612 **2** (NR) Cables bonded/grid defective	/
614 1,2,3,**4** (NR) Cracked/broken	/
615 **3** (R) Fire proofing	/
616 **4** (NR) Improper grade	/
617 **P** (NR) Missing nomenclature	/
620 **2** (NR) Rerack	/
621 1,2,**3**,4 (NR) Ring/cover repair/replace	/
622 1,**4** (NR) Roof condi ion – use comments	/
623 1,**4** (NR) Chimney Condition – comments	/
624 **4** (NR) Manhole needs cleaning	/
625 **1** (R) Secondary needs repair	/
626 4 (NR) No Holes in Manhole Cover	/
NETWORK PROTECTOR	
630 **2** (R) Barriers broken/damage	/
632 **1** (R) Oil leak	/
633 **2** (NR) Worn/damaged gasket	/
NETWORK TRANSFORMER	
635 **2** (R) Bushing Broken/cracked	/
637 **2** (R) Low oil	/
638 **1** (NR) Missing ground	/
639 **P** (NR) Missing nomenclature	/
642 1, **2** (R) Oil Weeping	/
643 **4** (NR) Rusted/paint peel	/
SWITCHGEAR	
651 1,**2**,3 (R) Barrier broken/damaged/unsecure	/
652 1,2,**3** (NR) Base broken/damaged	/
654 **2** (R) Cable not bonded	/
656 1,**2**,3 (R) Door Broken/Damaged	/

SWITCHGEAR	P/Q
657 **F** (NR) Excessive vegetation	/
659 **2** (R) Missing ground	/
660 **P** (NR) Missing nomenclature	/
661 **4** (NR) Other	/
662 **4** (NR) Rusted/Paint Peeling	/
TRANSFORMER	
672 1,2,**3** (R) Bushing Broken/Cracked	/
673 1,**2**,3 (R) Door Broken/damaged/unsecure	/
675 1,2,**3** (R) Elbows/tracking/burned	/
676 **F** (NR) Excessive vegetation	/
680 **1** (R) Missing Ground	/
681 **P** (NR) Missing nomenclature	/
682 **4** (NR) Mud/debris	/
684 1,**2** (NR) Oil Weeping	/
685 1,2,**3**,4 (NR) Pad broken/damaged	/
686 **4** (NR) Protection (ballards) damage	/
687 **4** (NR) Rusted/Paint peeling	/
688 1,**2** (NR) Pad Pushed Off Base	/
TRENCH	
690 **1** (R) Exposed Cable	/
692 **4** (NR) Pa h – Sunken	/
VAULTS	
700 **2** (NR) Cable missing bond	/
702 1,2,3,**4** (NR) Cracked/broken	/
703 1,2,**4** (NR) Damaged/broken cover	/
704 1,2,**4** (NR) Damaged/broken door	/
705 1,**2**,4 (NR) Damaged/broken ladder	/
706 1,2,**3**,4,P (NR) Improper grade	/
707 4,**P** (NR) Improper nomenclature	/
708 **4** (NR) Light not working	/
712 **4** (NR) Sump pump broken	/
713 **1** (R) Secondary needs repair	/
SUBMERSIBLE EQUIPMENT	
720 1,2,3,**4** (R) Excess Corrosion	/
721 1,2,3,**4** (R) Physical damage	/
722 1,**2** (R) Leaking	/
ANODES	
730 **3** (R) Missing	/
731 **3** (NR) Need replacement	/

KEY
PQ = Priority Quantity
NR = Maint.Code May Not Directly Affect Reliab.
R = Maint. Code May Affect Reliability
RP = Maint. Code May Affect Reliab. and Has Specific Program to Place to Address

Comments:

NG-0244 7/09

III. MAINTENANCE DATABASE

The Maintenance database consists of data downloaded from the Windows based hand held and data entered from the desktop computer. The Windows based hand held used in the field, can be downloaded to any National Grid desk top computer that is connected to the network and the inspector is logged on as a valid user of the UG Maintenance program. The National Grid desktop computer is also used to generate various reports and work tickets depending on the user's need. These reports are utilized to schedule and accomplish distribution maintenance work.

IV. MAINTENANCE SCHEDULE

Maintenance activities are scheduled by priority Levels. All "Level 1 Priority" conditions identified must be repaired/corrected within 1 week. All "Level 2 Priority" conditions identified must be repaired/corrected within 1 year. All "Level 3 Priority" conditions must be repaired within 3 years. Level 4 Priority is for inventory purposes only.

Once the Underground Circuit/Feeder is completed in the Underground Maintenance Database, the Level 2 and Level 3 Priority maintenance codes are downloaded into STORMS. Expense maintenance work goes straight to scheduling while the capital work goes to Underground Engineering. Level 1 Priority maintenance codes are communicated by the Underground Inspector directly to the field operations group for the area where the feeder is located.

V. COMPLETION OF MAINTENANCE CODES

The completion of Level 1 priority maintenance codes is performed by the field operations Supervisor or their designee. Level 2 and Level 3 priority maintenance codes are completed in the Underground Maintenance database once the 699 requirement is completed in STORMS for the work request associated with the maintenance code.

ALL MAINTENANCE WORK IS TO BE COMPLETED PER NATIONAL GRID UNDERGROUND CONSTRUCTION STANDARDS.

VI. RESPONSIBILITIES:

Distribution Engineering Services

1. Update program as necessary.

Customer Operations

1. Ensure the Underground Maintenance Program as outlined in this EOP is implemented properly and timely.
2. Select circuits to be patrolled for a running five-year cycle and ensure that the circuits scheduled for patrol are completed each year.
3. Provide qualified personnel as the inspectors, to provide consistent and accurate identified maintenance concerns/problems.
4. Ensure program is completed annually as required.

Underground Inspector

1. Demonstrate the ability to identify maintenance concerns and the aptitude to become proficient in the use of a hand held computer and desktop computer.
2. Demonstrate the understanding and requirements of this EOP.
3. Possess the ability to do walking patrols, collect information on a hand held, download to a desk top computer, edit data, provide requested information/reports/work tickets to supervision, and track/close out work completed in the database.

Contract Management Services

1. At the request of Customer Operations/Distribution Network Strategy obtain, schedule and manage contractors to perform inspections and perform required maintenance.
2. Ensure the Underground Maintenance Program as outlined in this EOP is implemented properly and timely.
3. Provide inspectors where applicable.
4. Ensure inspectors are trained.
5. Provide program management.
6. Ensure program is completed annually as required.

Asset Strategy and Policy

1. Provide input into program revisions.
2. Provide program management.
3. Ensure program is completed annually as required.
4. Ensure the Underground Maintenance Program as outlined in this EOP is implemented properly and timely.

Process and Systems

1. Provide and support database.

T&D Technical Training

1. Provide training upon request.

REFERENCE:

NY PSC Order 04-M-0159
NY PSC Order Order Adopting Changes to Electric Safety Standard, December 2008
Applicable National Grid Safety Rules and Procedures
Distribution Line Patrol and Maintenance NG-USA EOP D004
Elevated Equipment Voltage Testing NG USA EOP-G016
Transmission Line Patrol and Maintenance NG USA EOP – T007
Massachusetts DTE Directive 12/9/05

NG-USA EOP UG006

"Underground Inspection and Maintenance"

08/17/09

Changed levels from ABC to 1234 and added Underground Field Survey Worksheet.

PUC 2-15

Request:

What does National Grid estimate the impact of municipalities purchasing streetlights will have on the manual street light contact voltage testing? (p. 87)

Response:

The majority of the streetlights being evaluated for purchase are overhead streetlights sourced on wood poles, and their sale will not impact the existing manual contact voltage testing program for wood poles, which tests metallic objects on wood poles within reach of the ground. Streetlights with underground fed service having metallic surfaces that are exposed to the public would no longer be tested as part of the Company's manual contact voltage testing program if purchased by a municipality; instead, these streetlights would be included in the mobile elevated voltage testing if they are located in a contact voltage risk area.

PUC 2-16

Request:

Please provide a status update of the Tunk Hill project.

Response:

The Tunk Hill project is currently in construction with an expected completion date of June 1, 2014. Construction is approximately 10% complete with current activities including pole and anchor installations and replacements.

Prepared by or under the supervision of: Jennifer L. Grimsley

PUC 2-17

Request:

Please describe any efforts National Grid has made to communicate with municipalities to clarify police detail policies and/or attempt to reduce police detail costs.

Response:

The Company has met with its contractors to discuss police detail practices and the need for the contractors to report any unusual requests for police details. Situations which should be reported include when police arrive at job sites where the Company neither requested nor previously needed a police detail, and were not informed that a detail was necessary or where the Company has previously used flaggers and is now being required to use a police detail. Furthermore, in an effort to avoid unnecessary police details, the Company is meeting with towns prior to pruning to limit these incidents once work has begun. By being proactive in these instances and communicating ahead of time with the municipalities, the Company is attempting to better control costs and prevent any unexpected or unreasonable charges in the future.

PUC 2-18

Request:

Please expand the chart on page 67 of the proposed FY 2015 ISR plan to include Fiscal Years 2002 through FY 2009.

Response:

Please see the revised chart attached as Attachment PUC 2-18.

CAPITAL SPENDING BY KEY DRIVER CATEGORY AND BUDGET CLASSIFICATION

SPENDING RATIONALE	BUDGET CLASSIFICATION	FY 2002 ACTUAL	FY 2003 ACTUAL	FY 2004 ACTUAL	FY 2005 ACTUAL	FY 2006 ACTUAL	FY 2007 ACTUAL	FY 2008 ACTUAL	FY 2009 ACTUAL	FY 2010 ACTUAL	FY 2011 ACTUAL	FY 2012 ACTUAL	FY 2012 ACTUAL	FY 2013 ACTUAL	FY2014 BUDGET	FY 2014 FORECAST	FY 2015 BUDGET
Statutory/Regulatory	3rd Party Attachments	-	-	-	44,615	362,916	75,680	(123,199)	873,018	780,847	(909,712)	463,848	463,848	223,335	514,000		305,000
	Distr buted Generation	-	-	-	-	-	-	-	-	-	-	-	-	(675,256)	162,000		
	Land and Land Rights	-	-	-	220,925	199,978	244,275	313,141	310,128	274,560	281,215	185,520	185,520	127,922	190,000		179,000
	Meters - Dist	13,046,998	1,429,541	1,309,081	2,339,929	1,609,398	1,768,581	2,194,959	2,135,191	2,042,048	2,214,951	1,496,949	1,496,949	1,454,793	1,752,000		1,824,000
	New Business - Commercial	4,399,082	6,851,956	6,568,521	6,257,012	6,178,305	7,782,725	7,602,534	6,993,422	4,705,078	4,286,660	3,390,872	3,390,872	3,721,667	4,300,000		3,924,000
	New Business - Residential	3,964,702	4,169,707	4,408,848	5,658,767	5,111,949	6,564,788	4,951,161	2,856,774	3,256,239	3,529,650	2,833,259	2,833,259	2,885,908	3,025,000		2,870,000
	Outdoor Lighting - Capital	931,342	849,592	783,349	414,175	523,859	573,758	712,535	1,236,779	1,003,097	411,364	495,328	495,328	487,545	537,000		533,000
	Public Requirements	4,231,141	4,319,610	3,529,735	4,402,750	4,393,841	(790,093)	1,640,703	1,465,029	3,121,260	1,539,416	1,134,582	1,134,582	(1,230,546)	2,599,000		1,268,000
	Transformers & Related Equipment	2,773,079	3,418,034	3,882,182	2,679,295	4,504,947	4,812,334	6,595,658	5,301,415	4,128,756	3,277,796	3,074,796	3,074,796	3,414,855	3,430,000		3,634,000
Statutory/Regulatory Total		**29,346,343**	**21,038,441**	**20,481,715**	**22,017,468**	**22,885,194**	**21,032,047**	**23,887,492**	**21,171,756**	**19,311,885**	**14,631,340**	**13,075,154**	**13,075,154**	**10,410,223**	**16,509,000**	**17,909,000**	**14,537,000**
Damage/Failure	Damage/Failure	2,901,699	2,738,027	3,036,159	4,201,505	7,655,568	6,764,097	7,266,897	7,488,952	9,143,559	8,330,840	9,573,923	9,573,923	7,795,002	9,375,000		8,816,000
	Major Storms - Dist	-	-	-	-	609,088	678,175	375,380	856,490	(112,426)	4,863,261	3,418,936	3,418,936	9,720,450	675,000		1,000,000
Damage/Failure Total		**2,901,699**	**2,738,027**	**3,036,159**	**4,201,505**	**8,264,656**	**7,442,272**	**7,642,277**	**8,345,442**	**9,031,133**	**13,194,101**	**12,992,859**	**12,992,859**	**17,515,452**	**10,050,000**	**10,689,000**	**9,816,000**
Non-Infrastructure	General Equipment - Dist	1,003,171	799,994	1,079,177	238,630	54,233	12,601	324,847	154,236	391,872	60,548	148,707	148,707	191,193	105,000		102,000
	Corporate/Admin/General	-	-	-	1,791,686	(3,136,053)	2,441,291	(60,904)	(3,464)	(1,238,810)	645,055	117,838	117,838	889,752	150,000		-
	Telecommunications Capital - Dist	-	-	-	12,332	143,386	23,333	-	-	-	-	-	-	1,188,120			175,000
Non-Infrastructure Total		**1,003,171**	**799,994**	**1,079,177**	**2,042,647**	**(2,938,434)**	**2,477,226**	**263,943**	**150,772**	**(846,938)**	**705,603**	**266,545**	**266,545**	**2,269,065**	**255,000**	**787,000**	**277,000**
Asset Condition	Asset Replacement	439,262	709,703	349,535	3,924,209	5,828,465	8,314,885	12,462,029	10,851,628	12,574,361	5,604,107	9,766,995	9,766,995	6,984,455	11,377,000		11,957,000
	Asset Replacement - I&M (NE)	-	-	-	-	-	28,022	20,727	112,553	490,942	226,693	553,104	553,104	1,086,377	8,515,000		7,040,000
	Safety	-	-	-	-	-	-	76,680	(22,943)	-	-	-	-	-	350,000		514,000
Asset Condition Total		**439,262**	**709,703**	**349,535**	**3,924,209**	**5,828,465**	**8,342,907**	**12,559,436**	**10,941,238**	**13,065,303**	**5,830,800**	**10,320,099**	**10,320,099**	**8,070,832**	**20,242,000**	**16,780,000**	**19,511,000**
System Capacity & Performance	Load Relief	7,532,602	7,799,201	12,640,450	11,089,658	7,306,787	6,698,922	3,796,357	6,889,245	8,798,076	6,011,935	8,836,739	8,836,739	6,618,542	10,396,500		19,052,000
	Reliability	2,359,670	5,352,693	4,696,970	4,486,786	3,022,794	3,529,889	5,446,383	3,878,186	5,768,069	2,798,644	2,554,262	2,554,262	3,723,651	1,947,500		2,707,000
	Reliability - FEEDER HARDENING	-	-	-	-	650,810	1,316,796	4,315,685	3,828,491	2,888,145	1,984,135	2,564,239	2,564,239	907,019	200,000		-
System Capacity & Performance Total		**9,892,272**	**13,151,894**	**17,337,420**	**15,576,444**	**10,980,391**	**11,545,607**	**13,558,425**	**14,595,922**	**17,454,290**	**10,794,714**	**13,955,240**	**13,955,240**	**11,249,212**	**12,544,000**	**22,586,000**	**21,759,000**
Grand Total		**43,582,748**	**38,438,059**	**42,284,006**	**47,762,273**	**45,020,273**	**50,840,059**	**57,911,573**	**55,205,130**	**58,015,673**	**45,156,558**	**50,609,897**	**50,609,897**	**49,514,784**	**59,600,000**	**68,751,000**	**65,900,000**