STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

The Narragansett Electric Company
d/b/a National Grid
R.I.P.U.C. Docket No. 4382 Docket No. 4382
RE: FY 2014 Electric Infrastructure,
Safety, and Reliability Plan :

PREFILED DIRECT TESTIMONY OF

Gregory L. Booth, PE
President, PowerServices, Inc.
On Behalf of Rhode Island Division of Public Utilities and Carriers

February 28, 2013

Prepared by:
Gregory L. Booth, PE

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Prefiled Direct Testimony of

Gregory L. Booth, PE, President
PowerServices, Inc.

On Behalf of Rhode Island Division of Public Utilities and Carriers
Docket No. 4382

Table of Contents

DIRECT TESTIMONY OF GREGORY L. BOOTH, PE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR EMPLOYER.

A. My name is Gregory L. Booth. I am employed by PowerServices, Inc. ("PowerServices"), located at 1616 E. Millbrook Road, Suite 210, Raleigh, North Carolina 27609.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers (“Division”).

Q. WHAT DOES YOUR POSITION WITH POWERSERVICES, INC., ENTAIL?

A. As President of PowerServices, Inc., an engineering and management services firm, I am responsible for the direction, supervision, and preparation of engineering projects and management services for our clients, including the corporate involvement in engineering, planning, design, construction management, and testimony.

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A. I graduated from North Carolina State University in Raleigh, North Carolina in 1969 with a Bachelor of Science Degree in Electrical Engineering. I am a registered professional engineer in twenty (22) states, including Rhode Island, as well as the District of Columbia. I am also a registered land surveyor in North Carolina. I am also registered under the National Council of Examiners for Engineering and Surveying.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. I am an active member of the National Society of Professional Engineers ("NSPE"), the Professional Engineers of North Carolina ("PENC"), The Institute of Electrical and Electronics Engineers ("IEEE"), American Public Power Association ("APPA"), American Standards and Testing Materials Association ("ASTM"), the National Fire Protection Association ("NFPA"), and Professional Engineers in Private Practice ("PEPP"). I have also served as a member of the IEEE Distribution Subcommittee on Reliability and as an advisory member of the National Rural Electric Cooperative Association ("NRECA")-Cooperative Research Network, which is an organization similar to EPRI.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH ELECTRIC UTILITIES.

A. I have worked in the area of electric utility and telecommunication engineering and management services since 1963. I have been actively involved in all aspects of electric utility planning, design and construction, including generation and transmission systems, and North American Electric Reliability Corporation ("NERC") compliance.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE THE RHODE ISLAND PUBLIC UTILITIES COMMISSION?

A. Yes. I have testified before the Rhode Island Public Utilities Commission on numerous matters, including Docket Nos. 2489, 2509, 2930, 3564, 3732, 4029, 4307, 4218, 4237, 4360, and D-11-94. My testimony in Rhode Island has included filed and live testimony on previous Electric Infrastructure, Safety and Reliability Plan Fiscal Year Proposal filings by National Grid in Docket Nos. 4218 and 4307.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to introduce *Exhibit GLB-1*, Report of Gregory L. Booth, PE on the review of the National Grid Electric Infrastructure, Safety and Reliability Plan FY 2014 dated December 28, 2012 ("ISR Plan"). My testimony will briefly summarize the collaborative process between the Division and National Grid, which resulted in the ISR Plan filed December 28, 2012, together with summarizing the details of my report and my recommendations.

III. ISR PLAN EVALUATION PROCESS

Q. WOULD YOU BRIEFLY OUTLINE THE PROCESS WHICH LEADS TO THE DIVISION'S SUPPORT OF THE NATIONAL GRID ISR PLAN FILED ON DECEMBER 28, 2012 IN THIS DOCKET?

A. Yes.

- First, National Grid submitted an initial FY 2014 ISR Plan Proposal on November 5, 2012 to the Division. In collaboration with the Division, I performed an extensive review of this ISR Plan in the context of prior plans, historical spending, and new programs.
- Second, I prepared a detailed set of discussion items (included with my report) which were used during the November 29, 2012 conference with National Grid. During this conference, all issues and expenditures were discussed and a set of questions and action items was developed. National Grid submitted its responses to questions presented during the conference as Responses to the Division's First Set of Requests.
- Third, the Division submitted a second set of requests for which National Grid issued its responses on December 17, 2012.
- Fourth, PowerServices submitted a set of proposed adjustments to each category and line item to the November 5, 2012 National Grid Proposal.
- Fifth, the Division, PowerServices, and National Grid held a second conference on December 20, 2012 to finalize the adjustments and reach a consensus position.
- Sixth, subsequent to the December 28, 2012 filing by National Grid, I notified Ms. Grimsley of an error in one of the charts. Additionally, on January 14, 2013, Ms. Grimsley submitted to PowerServices, in response to a question during the December 20, 2012 conference, a document outlining the underground residential developments

in the cable replacement program showing the outages, duration, and other details supporting the need for the URD cable replacement program.

- Lastly, throughout the process, National Grid was open to the Division's recommended adjustments.

The following chart summarizes the adjustments by category and the agreement reached between the Division and National Grid which is represented in National Grid's December 28, 2012 filing:

Chart 5: Proposed FY 2014 Capital Outlays by Key Driver Category

SPENDING RATIONALE	INITIAL FY2014 PROPOSED BUDGET (11-5-12)	POWERSERVICES ADJUSTMENTS	FILED FY2014 PROPOSED BUDGET (12-28-12)
Statutory/Regulatory	$ 19,109,000	$ (2,600,000)	$ 16,509,000
Damage/Failure	$ 10,050,000	$ -	$ 10,050,000
Subtotal	$ 29,159,000	$ (2,600,000)	$ 26,559,000
Asset Condition Total	$ 21,042,000	$ (800,000)	$ 20,242,000
Non-Infrastructure Total	$ 255,000	$ -	$ 255,000
System Capacity and Performance Total	$ 13,544,000	$ (1,000,000)	$ 12,544,000
Subtotal	$ 34,841,000	$ (1,800,000)	$ 33,041,000
Grand Total	$ 64,000,000	$ (4,400,000)	$ 59,600,000

IV. COMMENTS ON WITNESS TESTIMONY

Q. HAVE YOU REVIEWED THE PRE-FILED TESTIMONY OF JENNIFER L. GRIMSLEY AND CRAIG W. ALLEN?

A. Yes.

Q. WOULD YOU PROVIDE ANY COMMENTS YOU HAVE IN REGARD TO THE FILED TESTIMONY OF THESE TWO WITNESSES?

A. Yes. The testimony of Ms. Grimsley and Mr. Allen accurately reflects the FY 2014 ISR Plan which the Division and PowerServices concurred would be an appropriate balance between system reliability and cost to enable National Grid to maintain a safe and reliable electric distribution system for its Rhode Island customers. Since the testimony and its Exhibit 1 do not detail the adjustment process and issues raised by the Division, I am including *Exhibit GLB-1* which provides details concerning the entire Division analysis and adjustment process and engineering justification.

V. REPORT SUMMARY

Q. PLEASE BRIEFLY SUMMARIZE YOUR REPORT ATTACHED AS EXHIBIT GLB-1.

A. The report contains an Introduction which describes the overall process and summarizes the adjustments which resulted in a consensus for the FY 2014 ISR Plan Proposed Budget of $59,600,000 for capital items, with a Vegetation Management Program expense budget of $8,476,000 and an Inspections and Maintenance Program expense budget of $3,779,000, including the new Contact Voltage Mobile Testing Program. The *Exhibit GLB-1* report section on Capital Investment Plan discusses in detail each major category: Statutory/Regulatory; Asset Condition; Non-Infrastructure; System Capacity and Performance; Vegetation Management; and Inspection and Maintenance, outlining the issues considered and the adjustments proposed, and the reasoning for the adjustments as accepted by National Grid. A detailed summary chart contained in the report as Appendix-1 shows each Spending Rationale and Budget Class with the November 2012 initial proposed budget, our recommended adjustments, and the December 28, 2012 Filed Proposed Budget.

The report contains a conclusion which supports the FY 2014 ISR Plan Proposal Budget as filed by National Grid on December 28, 2012. The conclusion also recommends four (4) additional action items.

VI. CONCLUSION

Q. DO YOU AND THE DIVISION SUPPORT THE NATIONAL GRID FY 2014 ELECTRIC ISR PLAN PROPOSAL FOR $59,600,000 IN BUDGETED CAPITAL EXPENDITURES, WITH $8,476,000 IN VEGETATION MANAGEMENT EXPENSES AND $3,779,000 IN INSPECTION AND MAINTENANCE EXPENSES?

A. Yes.

Q. WHAT ARE THE ADDITIONAL RECOMMENDATIONS YOU HAVE MADE IN YOUR REPORT EXHIBIT GLB-1?

A. The four (4) additional recommendations I have provided in my *Exhibit GLB-1* report are summarized in the following list, and are provided with additional discussion in my report Conclusion.

1. National Grid shall be required to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management program for the Division's review prior to submitting the Company's FY2015 ISR Plan Proposal, but in any event no later than August 31, 2014.
2. National Grid shall submit its detailed substation capacity expansion plans, including load projections, at least 120 days prior to filing its FY2015 ISR Plan Proposal, but in any event no later than August 31, 2014.
3. National Grid shall submit its Metal-Clad Switchgear replacement program cost-benefit analysis to the Division no later than August 31, 2013.
4. The Company should submit its final resolution of the Verizon vegetation management negotiations prior to its next ISR Plan to the Division.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

GLB EXHIBIT-1

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

REPORT OF

Gregory L. Booth, PE, President
PowerServices, Inc. d/b/a PowerServices and Consulting, Inc.
On Behalf of Rhode Island Division of Public Utilities and Carriers
Concerning
The Narragansett Electric Company d/b/a National Grid's Proposed
FY 2014 Electric Infrastructure, Safety, and Reliability Plan
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PREFACE

PowerServices, Inc. was engaged by the State of Rhode Island Division of Public Utilities and Carriers ("RIDPUC") to evaluate the Electric Infrastructure, Safety and Reliability ("ISR Plan" or "Plan") Plan FY 2014 Proposal submitted by National Grid. As part of the review of the plan, numerous data requests were submitted and responses provided by National Grid. Additionally, conferences were held with National Grid and their key personnel involved in the development of the Plan. The Legislative Act amending Chapter 39-1 "Revenue decoupling", 39-1-27.7.1, provided National Grid the right to file an ISR Plan and receive considerations for the Plan. The statute provides for evaluation by the Division, and for National Grid and the Division to reach an agreement on a proposed plan and submit a mutually agreed upon Plan. The following report describes the process and consensus position reached between the Division and National Grid.

REPORT OF

Gregory L. Booth, PE, President
PowerServices, Inc. d/b/a PowerServices and Consulting, Inc.
On Behalf of Rhode Island Division of Public Utilities and Carriers
Concerning
The Narragansett Electric Company d/b/a National Grid's Proposed
FY 2014 Electric Infrastructure, Safety, and Reliability Plan
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Table of Contents

I. INTRODUCTION

PowerServices was engaged by the Rhode Island Division of Public Utilities and Carriers ("Division") to assist in the evaluation of the initial National Grid Electric Infrastructure, Safety, and Reliability Plan FY 2014 Proposal (the "ISR Plan" or "Plan") dated November 5, 2012, and the final Electric Infrastructure, Safety, and Reliability Plan FY 2014 Proposal dated December 28, 2012 as filed in Docket 4382. The evaluation followed the same process of analysis completed for the FY 2012 ISR Plan and FY 2013 ISR Plan. This Report will include an explanation of the process for the initial ISR Plan proposal evaluations and collaborative efforts, resulting in a reduction of FY 2014 capital spending on infrastructure projects, operation and maintenance ("O&M") expenses for Vegetation Management ("VM"), and O&M expenses for an Inspection and Maintenance ("I&M") program from the Company's FY 2014 ISR Plan Proposal submitted to the Division November 5, 2012. This process, as provided for in Chapter 39-1-27.7.1 of the General Laws entitled "Revenue Decoupling", is for the Company, prior to the start of each fiscal year, to submit its ISR spending plan and consult with the Division regarding said Plan. The Division is also bound by statute to "cooperate in good faith to reach an agreement on a proposed plan." This process ultimately resulted in the Division and the Company reaching agreement on an appropriate level of the capital spending and O&M expenses for FY 2014 to be included in what is now the Company's filing of an Electric ISR Plan in Docket No. 4382.

The Company provided its initial proposed FY 2014 plan to the Division in a November 5, 2012 submittal. The initial ISR Plan followed very closely the format and principals agreed to in the FY 2012 ISR Plan and FY 2013 ISR Plan, as approved. Many of the Company's budget line items are structurally different than the previous Plans with modifications in the cost structure, although the Company generally met the guidelines used to reach agreement for the cost during the last evaluation process.

An in-depth analysis of each line item and component included in the FY 2014 ISR Plan was undertaken. The evaluation and analysis process was performed utilizing the following procedure: (1.) the preliminary Plan filed with the Division was closely evaluated, (2.) a November 29, 2012 conference call (Appendix-1 is the agenda for this call) was held between the Division, PowerServices, and the Company, in which each component of the ISR Plan was discussed in detail, (3.) during the November 29, 2012 conference call, a series of questions were posed to the Company on 13 major categories and 46 subsets of these categories. Additionally, numerous outstanding questions and data requests during the call were outlined for which the Company agreed to provide responses, and these responses were provided back to the Division and PowerServices as Data Request No. 1 Responses, (4.) PowerServices prepared a detailed series of data requests which were served on the Company and the Company provided responses to these data requests and identified them as Responses to Division's Data Request No. 2, (5.) on December 18, 2012, PowerServices submitted through the Division to the Company, a spreadsheet which proposed a series of adjustments to the various components of the FY 2014 ISR Plan, (6.) a second conference call was held between PowerServices, the Company, and the Division on December 20, 2012 to further discuss the data requests and the adjustments we believed were appropriate to the various components of the FY 2014 ISR Plan, (7.) during the conference call on December 20, PowerServices, the Division, and the Company reached consensus on the appropriate adjustments to the initial FY 2014 ISR Plan Proposal, and agreement was reached on the final cost to be incorporated for each of the components of the FY 2014 ISR Plan, and (8.) the overall analysis was an iterative process, which included detailed discussions of each ISR Plan spending rationale category, including Capital Expenditures, the VM Plan, and the I&M Plan, and the Company included each of its area experts in the discussions as we worked toward a final plan for FY 2014 which would have the support of the Division. This series of telephone conferences and data requests were utilized in discussions with various individuals in the Company to provide full assessment and gain clarification in each area. The requests and responses referred to above will be made part of the record through a filing of same by National Grid.

The Company has been transitioning several of its historic programs along with adding some programs, such as the contact voltage testing program. Additionally, the Company has been migrating from the substation flood mitigation programs included in previous ISR Plans to an overall substation capacity enhancement and reliability program. This transition from a substation flood mitigation program to a substation capacity and reliability program makes any direct correlation between the previous flood mitigation program and the new program difficult, at best. Also, programs such as the Feeder Hardening Program are being phased out, while a new inspection and maintenance program is being incorporated. As a result of the transition of certain programs, discussions concerning the substation program should start earlier than has occurred historically between the Company and the Division.

Through the analysis and assessment process, including multiple discussions with Company representatives, consensus on the rationale for adjustments and the final dollar levels was reached between the Division and the Company. Among the items utilized by the Company, the Division, and PowerServices in reaching a consensus were the quarterly reports comparing the historical ISR Plan budgets to actual expenditures to the proposed budget, together with the historical budgets and spending by category as reflected on Appendix-2. Additionally, there was substantial discussion concerning the storms and their impact on each category. The FY 2014 ISR Plan, as adjusted during the evaluation process, is reflected in the Company's December 28, 2012 filing with the Rhode Island Public Utilities Commission. Appendix-3 lists a Summary of the Capital Outlays by key driver category and budget classification, as originally proposed by the Company on November 5, 2012, with adjustments listed, and the Docket No. 4382 filed budget dated December 28, 2012. The following is a detailed discussion of the categories and adjustments.

II. CAPITAL INVESTMENT PLAN

Overview

I have evaluated the $59,600,000 FY 2014 Capital Spending Plan proposed by the Company, along with its supporting testimony and exhibits as contained in its filing dated December 28, 2012. I first reviewed the initial proposed ISR Plan submitted to the Division dated November 5, 2012 in the amount of $64.0 million. Over a period of approximately six (6) weeks, there was an iterative process in which modifications to the Company's original proposed Capital Spending Plan were discussed. A consensus was reached concerning each of the Spending Rationales and the five (5) major categories. The following is a comparison of the Company's initial filed request in November 2012, our adjustments to the initial request, and the Chart 5 Proposed FY 2014 as filed in Docket No. 4382. The $59.6 million is the consensus level reached through the evaluation process.

Chart 5: Proposed FY 2014 Capital Outlays by Key Driver Category

SPENDING RATIONALE	INITIAL FY2014 PROPOSED BUDGET (11-5-12)	POWERSERVICES ADJUSTMENTS	FILED FY2014 PROPOSED BUDGET (12-28-12)
Statutory/Regulatory	$ 19,109,000	$ (2,600,000)	$ 16,509,000
Damage/Failure	$ 10,050,000	$ -	$ 10,050,000
Subtotal	$ 29,159,000	$ (2,600,000)	$ 26,559,000
Asset Condition Total	$ 21,042,000	$ (800,000)	$ 20,242,000
Non-Infrastructure Total	$ 255,000	$ -	$ 255,000
System Capacity and Performance Total	$ 13,544,000	$ (1,000,000)	$ 12,544,000
Subtotal	$ 34,841,000	$ (1,800,000)	$ 33,041,000
Grand Total	$ 64,000,000	$ (4,400,000)	$ 59,600,000

The Company projects the need for $16,509,000 in Statutory/Regulatory spending, and $10,050,000 million in Damage/Failure spending. This is approximately forty-five percent (45%) of the ISR Plan Capital requirements. These budgeted levels are supported by historical spending levels and reflect the completion of the Shun Pike Substation, which is a substation required for a direct retail customer service. All of the projects in these categories, with the exception of the Shun Pike Substation, are not precisely defined because specific customer requests have not been made and damage or failure is yet to occur. For that reason, historical spending serves as the primary method to develop a budget. The economic conditions are a factor considered in adjusting historical costs. There are both upward and downward trends in new construction costs combined with the effects of inflation on construction cost. The housing and commercial construction industry remains depressed, while the cost of raw materials and construction cost continue to escalate, particularly petroleum based products such as underground cable and all associated transportation. The first three quarters of actual FY 2013 spending for Statutory/Regulatory was approximately $2,600,000 lower than budget, even with some costs for the Shun Pike substation in FY 2013. The Company agreed to lower the FY 2014 budget for Statutory/Regulatory based on the continued trends from $29,159,000 to $26,559,000.

Since the budgets for these categories are not project specific, but rather based on the Company's best estimate using historical cost trends combined with most recent trend data, a mechanism for reconciliation of the actual expenditures to the budget projections was agreed upon in the FY 2012 filing, and will continue. This mechanism will reconcile the annual differences between the projected budget and the actual expenditures for the non-discretionary capital spending.

The three categories, which are discretionary in the sense they are based on engineering, safety, reliability and economic analyses, account for the remaining fifty-five percent (55%) of the proposed capital budget. The remaining three (3) major categories of spending rationale for the FY 2014 budget are Asset Condition, Non-Infrastructure, and System Capacity and Performance. It is important to note that the Flood Damage Avoidance and Mitigation cost associated with engineering and substations is now rolled into the Asset Condition category, and is not separately identified. This is making the distinction between substation flood mitigation and capacity and condition relief of the substations more difficult to distinguish. Later in this Report, I will discuss recommendations related to this specific area in order to proceed with the evaluation process of substation capacity and expansion earlier than the customary process. For the three categories (Asset Condition, Non-Infrastructure and System Capacity and Performance), the initial proposed budget was $34,841,000, which has been adjusted down in the final FY 2014 ISR Plan filing, based on the consensus between the Division, PowerServices, and the Company, to $33,041,000. I will discuss each of these categories separately, explaining the $1,800,000 reduction. I will also discuss the rationale for the substantial adjustments and explain new cost intensive programs included. The following is discussion of each category.

A. Statutory/Regulatory Category

The initial proposed FY 2014 ISR Plan included $19,109,000 of Statutory/Regulatory Cost. After reviewing the historical plans, together with FY 2013 Actual Spending vs. Budgeted Spending, the Company and Division reached the consensus that this category should be adjusted downward to $16,509,000. The Damage/Failure category was not adjusted, since it reflected historical spending. Furthermore, there was substantial discussion and evaluation as it related to recent storms and how those storms may have an influence on the Damage/Failure category.

The commodity cost increase associated with the Statutory/Regulatory projects is 3%, which is consistent with the labor and material cost increases being seen in the electric utility industry. The costs which are now included for the budget in Statutory/Regulatory reflect the continued weak economy and substantially lower residential and commercial growth in construction. The finalization of the Shun Pike Substation, which is required for an industrial customer and was a part of the FY 2013 budget, is included for completion in the FY 2014 budget. The cost estimate for this project includes $800,000 of Contribution-In-Aid-of-Construction ("CIAC"), which has been reflected in the budget for this project. The Damage/Failure actual expenditures for the first six months of the FY 2013 budget are slightly lower than the projected first six months of the FY 2013 budget. By reflecting these historical levels of expenditure, combined with the inclusion of the I&M Plan, Level I Category, and one new metal-clad station replacement, the estimated FY 2014 budget is determined to be an acceptable level. All of this was taken into consideration, and the Damage/Failure category was left unchanged from the original proposal of $10,050,000.

This brings the non-discretionary categories of Statutory/Regulatory and Damage/Failure to $26,559,000, which is 45% of the total Capital Investment Budget by Key Driver Category.

B. <u>Asset Condition Category</u>

The predominant programs that resulted from this reliability assessment and annual reporting process begun in 2001 included a Feeder Hardening Program, a Feeder Health

Program, and associated Operation & Maintenance reliability enhancements. These programs were successful and have now matured, resulting in the need for a transition to a continually sustainable program. In the FY 2013 ISR Plan, the Company continued a program overlap which maintained the Feeder Hardening and Reliability O&M programs, and the new I&M Program added in FY 2012 which is intended to become a portion of the future sustainable infrastructure asset management program. The Asset Condition Category has an approximate $9,000,000 increase from FY 2013, which is driven by several items including the fact that the majority of these dollars are now from the maturing I&M Program as well as three new or expanded programs, which are: (1.) the underground rehabilitation program; (2.) the year on year cycle battery replacement program; and (3.) arc flash hazard mitigation program for 480 volt network system facilities.

1. The underground rehabilitation program includes the substantially aging paper and lead cables and duct bank system on main circuits, first evaluated in the 2001 reliability assessment, and underground rural distribution local reliability issues. For the underground rural distribution cables, the primary solution included in the initial rehabilitation program is a cable injection process which costs approximately 1/5 of what a full cable replacement program would cost. This injection process carries with it, from the vendor, a 20 year warranty. This is currently the most prudent and cost effective manner with which to proceed in solving the cable and underground reliability degradation. The paper and lead cables in the duct bank system were determined during the 2001 reliability assessment to be 60 to 80 years old, but in

satisfactory condition. The new I&M program, some 11 years later, is identifying cable deterioration that needs to be addressed. Additionally, the direct buried underground distribution cables installed before 1993 are demonstrating an increasing failure rate. There were approximately 118 events identified at underground risers and fuse operations, with average outage duration of these events exceeding 6 hours each. Furthermore, since there is a very small amount of concentric neutral failure taking place, cable injection is a real solution in lieu of entire cable replacement.

2. Additionally in this category is a perpetual year on year cycle battery replacement program. The entire functionality of the relay and protection schemes and equipment in the substations, both for substation equipment protection and feeder protection, is contingent on the battery systems' functionality and their quality of performance. A battery system replacement program is not only prudent, but essential, since a dead battery in a substation could result in significant equipment failures and expose the public to substantial electrical hazards and risk.

3. In the 2007 National Electrical Safety Code (NESC), arc flash hazard mitigation standards were promulgated as part of the expanded NESC work rules. These standards have been further updated and modified in the 2012 Edition of the NESC. The Company has performed extensive analyses, particularly relating to 480 volt network systems, and has found that the incident energy level that an employee working in or around energized network system cables would be exposed to at 480 volts significantly exceeds any flame retardant clothing or other functional personal protective equipment available. What this means is utility workers currently working on the network system 480 volt cables and equipment are exposed to arc flash heat

levels and durations that will cause debilitating or life threatening third and fourth degree burn injuries. This means an overall mitigation program needs to be developed in a prudent manner which will allow for work to transpire without taking significant outages on the underground network systems. The Company has developed a vacuum circuit interrupter and secondary switch isolation program which will allow for isolation of areas to be worked on without imposing outages on the customers, while providing for the protection of the workers. This mitigation program is in its initial stages, however, it is essential to both reliability and worker safety. During our discussions with the Company, it was agreed that the arc flash hazard mitigation program would be accomplished over a 6 year timeframe, rather than a 5 year timeframe. This would reduce the first year's cost from $550,000 to $250,000. As part of the overall discussions related to cost adjustments, it was agreed that the underground rehabilitation program could be essentially cut in half and, with that reduction combined with shifting the approximately $300,000 saved in the arc flash program to the rehabilitation program, the real anticipated expenditure in FY 2014 would be $1,500,000.

The FY 2014 Asset Condition category is budgeted at $9,621,000 above the FY 2013 budget. As noted above, there are numerous reasons for this higher budget level, the most significant of which are the new I&M projects, as identified in this new program, that have increased the cost. However, two major programs that were previously under the system capacity category are now reflected in the I&M programs. These are the Feeder Hardening and Reliability programs, which have a substantial reduction in investment. The Feeder Hardening program has dropped from $1,500,000 to $200,000 from FY 2013 to FY 2014. The Reliability program has dropped from $4,287,000 to $1,947,500 from FY 2013 to FY 2014. This transfer of dollars between the Asset Condition Category and System Capacity and Performance Category is driven predominately by the transition to the I&M program. This means the actual net increase cumulatively for both these categories is $4,982,500. The majority of the increase, which is driven by the Inspection and Maintenance identified programs, comes from the 3 new programs previously discussed. Additionally, the battery replacement program is being implemented with a 20 year cycle. As previously noted, there is a significant arc flash hazard mitigation program that is being implemented. In addition, the metal-clad switchgear replacement program is being initiated in FY 2014 and will continue for many years. This is a capital intensive program.

There are several issues that should be considered by the Company, and separate reports should be submitted to the Division before October 2013 to allow for adequate and reasonable evaluation, including all cost benefit studies (which is currently underway according to discussions with the Company). Additionally, as part of the metal-clad switchgear replacement program and cost benefit study, the Company should consider a spare mobile metal-clad secondary system which could be acquired and maintained at a cost of approximately $300,000, allowing for the deferral of metal-clad replacements, since the outage risk would be mitigated by having a mobile metal-clad secondary to be moved into place. Additionally, such mobile metal-clad switchgear would allow for backup in the event of other station failures or flood events, and would provide a flood mitigation component to the overall flood mitigation plan and system capacity requirements. Also a part of a major reliability component of the Plan under the Asset Condition is the Eldred Substation moderation and feeder expansion to back up the Clark Street Substation. Again, this is a capital intensive project under Asset Condition.

Each of these capital intensive programs were closely evaluated and extensively discussed with the Company, and it was determined that these programs were justified. The arc flash program cost has been modified through discussions and these dollars will be expended over a longer period of time. The overall resulting consensus was that the Asset Condition category would be reduced by $800,000, from $21,042,000 to $20,242,000.

C. <u>Non-Infrastructure Category</u>

This category is for telecommunications and other capital expenditures needed for operation, which are neither related to condition nor system capacity. I consider this $255,000 of capital expenditures prudent and necessary, while consistent with prior costs adjusted for construction cost escalation.

D. <u>System Capacity and Performance Category</u>

The Company has included in the FY 2014 ISR Plan the new Volt/Var program. A significant number of data requests were submitted on this program, and the Company provided both written responses and participated in lengthy discussions in regard to this proposed new program. The Company was expecting a demonstration project to cost between $3,000,000 and $6,000,000 over multiple years, with the FY 2014 Volt/Var plan proposed at $1,500,000. Such programs are intended to achieve optimization of line voltage and line power factor for better circuit performance, voltage delivery to the customers, and reduction in power line losses. I have evaluated the Company's current power factor correction and voltage control programs, as well as their system engineering modeling. It is my opinion that, based on this review as well as data responses and my discussions with the Company, the Company had not thoroughly developed the scope for the pilot program, and is proposing to implement a potentially costly pilot program prematurely. I recommended that, before the Company invests significant additional dollars in a Volt/Var optimization program, that the Company not only develops a comprehensive scope, but more importantly utilizes its sophisticated distribution system engineering modeling software and tools to evaluate the most appropriate initial Volt/Var program by circuit. PowerServices and the Division considered this an excessive expenditure at this time, particularly since the overall system analysis and scoping of such a program has not been fully developed. While I pointed out to the Company that I support the economic benefits associated with power factor correction optimization and voltage optimization, I believe that the sophisticated programs that are being tried by some utilities have proven not to show cost benefit, whereas the conventional power factor optimization and voltage optimization programs show a significant cost benefit. Many of the industry leaders, including vendors of the sophisticated equipment in the marketplace, have admitted that there is little economic benefit associated with the more sophisticated Volt/Var optimization equipment applications. The majority of the economic benefit is derived from power factor optimization and voltage control, which can be done with the conventional equipment in the marketplace without the implementation of a full "Smart Grid" protocol.

The discussion and recommendations were to first begin with detailed studies, using the Company's sophisticated engineering Cyme software to develop the program. There is recognition that the current control scheme on the capacitors placed on the feeders is predominately a time clock scheme, and needs to be completely revamped from a control perspective combined with an optimization of size and location for the capacitor banks. It was agreed that most of this could be done through the existing system models and software that the Company has, and they will do this on six feeders and will put in the metering and evaluation of those feeders to determine the economic benefit. Therefore, we strongly recommend that National Grid, for the FY 2014 Volt/Var pilot program develop a scope that should be based on a multi-step process, which would include:

1. A comprehensive engineering model of each circuit in the pilot program identifying the circuit uncorrected power factor and then using the engineering model to establish the capacitor placement for power factor optimization on each circuit. The same process would be used for implementation of voltage levels and feeder regulation.
2. The next phase of the engineering analysis would be the installation of the equipment, including controls and monitoring. Monitoring would evaluate both energy consumption and demand by circuit in a manner to allow for the establishment of demand-side management improvements through voltage control, and both demand and energy reduction savings through power factor

optimization. The accumulated data, both through modeling and actual recording, would then be entered into a cost benefit analysis and a study would be produced that would show the cost and benefit associated with power factor optimization and voltage control. This study would be provided to the Division before the next ISR Plan is filed.

Once this initial pilot program has been completed, the Company, in conjunction with the Division, could evaluate the prudency of proceeding with a similar program on other feeders, and the overall economic benefit to the ratepayers associated with the implementation of such a program system-wide. Based on these extensive discussions and a substantial modification in the scope of the initial phase of the program, it was agreed the Volt/Var program should be cut back to $500,000 for FY 2014. Based on what is accomplished in FY 2014, a detailed scoping document and program detail will be developed for future fiscal years, in combination with cost benefit analyses.

The Company initially proposed to expend $13,544,000 in the System Capacity and Performance Category. Through mutual agreement, this category was reduced to $12,544,000 for FY 2014 by substantially adjusting the dollars that would have been spent in the proposed Volt/Var pilot program. The System Capacity and Performance Category represents projects which include increased substation capacity, distribution conductor replacement, and the addition of capacitors and sectionalizing equipment to meet the capacity and voltage delivery requirements of the system predicted for the existing and future projected load additions. The Company has projected a demand growth rate ranging from 1% to 2%, depending on the specific substation or circuit. The overall capacity requirement analysis, particularly for substations, has been predicated on an N-1 Analysis, assuming that one major component is lost and the remaining components, particularly substations, can pick up the load without an extended outage. One of the major projects included in this category is the 4 kV to 12 kV conversion program. The power line losses on the 4 kV system are nearly 9 times greater than on the 12 kV system and that, combined with the lack of sufficient capacity and load switching capability, makes the conversion program cost justifiable as well as reliability and safety driven. The feeder hardening program will be fully completed and phased out during FY 2014 with only $200,000 in total expenditures. The Company will be completely transitioned to its new I&M program and, for that reason, not only will the feeder hardening program, after FY 2014, be no longer a category of cost, but also many of the reliability projects should be identified within the I&M program and, therefore, the I&M program should generally move to a levelized expenditure consistent with the projected level in FY 2014.

Within the System Capacity and Performance Category, there are significant dollars associated with the breaker replacement program. The Company has an aging substation breaker plant to be modernized. Age is not the main driver for the replacement of the breakers. There are however, some very old air magnetic and old oil technology breakers, and old recloser technology, which represent both reliability and repair problems for the Company due to the age of the breakers, their outdated technology, and the lack of spare part availability, which make the replacement a program necessity. For that reason, the Company has identified the first level of these breakers to be replaced. This is anticipated to be an ongoing program for several years. In previous Electric ISR Plans, the Company has allocated significant dollars for engineering studies associated with the Substation Flood Mitigation Program and projects. This Substation Flood Mitigation category is now transitioning to a Substation Capacity Relief Program and, because these two programs are so interrelated and are being melded together at this time, there is not a clear distinction between capacity relief projects and flood mitigation projects. The substation expansion and capacity projects, as proposed in FY 2014, serve both a capacity relief requirement and flood mitigation requirement. Due to the high cost of substation projects and the future implementation of higher cost substation capacity relief projects included in the long term projections of the Company, it is recommended the Company provide its studies on substation capacity relief to the Division well in advance of its normal filing of the proposed Electric ISR Plan schedule. It is recommended that, by the end of August of each year, the Company provide to the Division the Capacity Relief Plan to include the proposed and alternate plans for additional substations and increased substation capacity. The reason for the recommendation that these planning components to be provided in advance of each year's ISR Plan is to give the Division and its Consultants adequate time to evaluate all of the alternatives and options, and the extensive impact of these very expensive substations, which generally have a two to four year budget cycle from start to finish. Furthermore, it is recommended that the Division and Company agree on periodic discussions of the quarterly ISR Plan filings in order to achieve a more effective communication and consensus building process for each year's subsequent ISR Plan.

The I&M program capital expenditures are being expanded to incorporate the sub-transmission and underground systems for FY 2014. This expansion of the I&M program accounts for a portion of the additional capital expenditures above historical levels. The Tunk Hill reliability project accounts for some $1,000,000 worth of capital investment in reliability improvement associated with a 17.5 mile long feeder. Approximately 2.5 miles of this feeder are involved in a substantial upgrade program and the utilization of insulated tree wire. Although this project is associated with improving the reliability to only 800 customers, which in of itself would have a marginal cost benefit, it is unfortunately an area with such serious reliability problems they will be exacerbated over time if there is no mitigation. Since areas even with relatively small customer concentrations should expect an acceptable level of reliability, this substantial expenditure is warranted to bring about an improvement in the level of reliability to this particular portion of the system so these customers are brought into an acceptable range of reliability.

E. Vegetation Management Category

The Company's initial ISR Plan submitted to the Division November 5, 2012 included $8,676,000 for the vegetation management program, which incorporated the Enhanced Hazard Tree Mitigation (EHTM) program. My evaluation of the Vegetation Management Program was performed on multiple levels. First, I considered the overall Company reliability indices and determined they have continued to remain better than the Commission's benchmarks. Second, I carefully considered the Company's justification for its more aggressive VM Program and its incorporation of an Enhanced Hazard Tree Mitigation ("EHTM") Program. In previous ISR Plan assessments, the Company provided an excellent presentation to the Division and me on these programs. Third, I evaluated the Company's anticipated reliability improvement and the justification for the proposed budget expenditures, considering both the Company's reliability performance and the present depressed economy. Lastly, the impacts of recent severe storms (Irene and Sandy) were considered when evaluating the expenses budgeted for both programs. The Company and Division reached a compromise position on all these programs while balancing these issues and concerns.

The Vegetation Management ("VM") program includes a 5% cost increase in contract labor, which is consistent with the increases seen in the industry. The costs incorporated in this program also include a significant component associated with police and flag detail. In particular, it should be noted that the police and flagging escort cost increased more than 8%, and that, in certain towns, the rules require an 8 hour minimum, regardless of how many hours police escorts are required in the vegetation management circuit area. The impact of hurricanes Irene and Sandy were discussed and evaluated. The Company explained its assessment of the storms, which concluded that Irene had a much greater impact than Sandy. The Company evaluated the 19 worst performing circuits and identified 2.7 tree contacts per mile. Hurricanes leave weakened and damaged trees, which are later impacted by disease. Furthermore, the Company contends it will experience a re-sprout problem from the two (2) storms, making a continued aggressive cycle clearing program necessary. The proposed VM program now incorporates sub-transmission lines with an aggressive 4 year cycle. The program is incorporating 15 circuits per year, and includes pockets with extremely poor performance, and with frequent fuse trips. During discussions, it was agreed that the hazard tree portion of the program could be reduced by $200,000, or nearly 20%. The remainder of the VM program is consistent with the cycle clearing discussions and cost levels of historical years, and the level of system to be involved in the VM process each year. It should be noted that each year there has been a discussion of the Company delivering a statistically valid economic benefit analysis associated with the VM program, including the cycle trimming portion of the program and the enhanced hazard tree mitigation program. Although such an economic benefit analysis has not been completed to date, it would be anticipated that the Company should be in a position to deliver such an analysis with the FY 2015 Electric ISR Plan, and it should do so. The vegetation management program was proposed at $8,676,000 and has been adjusted down to $8,476,000 as filed in the December 28, 2012 Docket No. 4382 filing. This is only approximately 2.7% above the level of expenditures for FY 2013, which, if adjusted for the inflation associated with the annual increase in contractor labor cost and police cost, there is actually a slight reduction from historical expenses.

I have consistently recommended a slower transition from the historical VM Program to the Company's proposed more aggressive spending level once a more reliable database can be established to support higher levels for Vegetation Management that can truly be economically justified, as previously speculated by the Company. In order to accurately measure the cost benefit of the VM and EHTM, the Company should utilize its Outage

Management System and other systems to track its outages and reliability performance associated with VM and EHTM. The Company should utilize these systems to track the outages by circuit which have been addressed by the VM and EHTM, and compare both the outage rates and cost of Damage/Failure on the circuits with completed VM cycles versus the circuits that have not been a part of the cycle program. This will require that the Damage/Failure Capital Cost be subdivided into tree related and non-tree related cost, and cost by circuit identifying whether the circuit has been part of the VM and EHTM Program. This will allow a differentiation of Damage/Failure Capital Costs between circuits based on the Company's completion of VM and EHTM work. The key issue is how to quantify the impact of these preventative maintenance programs. On the first level of evaluation, National Grid currently collects outage statistics and categorizes the number of events and duration for each outage event. These outage statistics do provide a measure of tree related customer minutes interrupted (CMI); however, vegetation related outages are not subdivided into those that would have been mitigated by the EHTM Program. To address the first level of evaluation, the Division recommends that National Grid begin tracking vegetation related outages caused by hazard trees to supplement its current statistics. The second level of evaluation will need to address the operation and maintenance (O&M) expenses and capital costs attributable to vegetation outages. The Division recommends that National Grid begin tracking the associated expenses and capital costs incurred to restore the electric system after a vegetation related outage event. Once National Grid begins tracking these directly attributable costs, the Damage/Failure Capital Cost budget category can be evaluated more completely. Currently, it is not clearly demonstrated what portions of this budget category are driving the overall upward trend for this type of spending. Although escalation of labor, materials, and fuel costs is a major portion of the continued upward trend in costs, the Company has implemented no mechanism to track the cost benefit analysis of any preventive maintenance program, particularly the VM and EHTM Programs, for which it contends there is a distinct cost benefit. We have described above just one option for tracking the cost benefit.

The Division would recommend tracking the program benefits for the VM Program over 4 years, since this represents a complete VM Program cycle. The program's cost/benefit could then be reviewed annually based upon a rolling 4-year window. National Grid has committed to providing such an analysis based on its tracking the more detailed outage and accounting information as described previously. Trend lines for the Damage/Failure Capital Costs and VM and EHTM Programs could be compared with the outage trend lines, and yield both a cost/benefit analysis and a reliability analysis. At the end of 4 years there should be a distinct pattern. The Company may wish to go back and gather historical information in order to start with a time frame that is prior to the implementation of a 4 year clearing cycle and the EHTM Programs. In addition, there should be an inflation adjusted evaluation to eliminate annual aberrations due to price changes. The Division would expect to see the results of such a study as part of the FY 2015 ISR Plan supporting materials. Additionally, the Company remains in negotiations with Verizon concerning vegetation management cost sharing consistent with the Joint Ownership Agreement. The Division is awaiting the results of these negotiations.

The following Chart compares the initial budget request and that adjusted to consensus with the Division.

Vegetation Management Proposed FY 2014 Spending

SPENDING RATIONALE	BUDGET CLASS	Initial FY2014 Proposed Budget (11-5-12)	PowerServices Adjustments	Filed FY2014 Proposed Budget (12-28-12)
Vegetation Management Program	Cycle Prune (Base)	5,230,000	-	5,230,000
	Cycle Prune (Recovery)		-	-
	Hazard Tree - EHTM	950,000	(200,000)	750,000
	Post Irene EHTM		-	-
	Sub-T (off & on road)	724,000	-	724,000
	Police/Flagman Detail	525,000	-	525,000
	All Other Activities	1,247,000	-	1,247,000
Vegetation Management Program Total		**8,676,000**	**(200,000)**	**8,476,000**

I find the $8,476,000 FY 2014 level and a 4 year clearing cycle based on the Company's enhanced Vegetation Management Program to be appropriate, considering the anticipated level of benefits while balancing today's difficult economic environment. The acceptance of this level does not, however, mean PowerServices or the Division expect the Company to forego its rights to collect a portion of its costs from Verizon.

F. Verizon Joint Ownership Agreement Vegetation Management

There continue to be negotiations taking place between the Company and Verizon as they relate to Verizon's compliance with the VM requirements of the Joint Ownership Agreement. This issue was addressed in the Hurricane Irene proceedings of Docket D-11-94. As a result of that Docket, the Division expects the Company to proceed aggressively and in a timely manner with negotiations with Verizon to bring Verizon in line with the expectations of the Joint Ownership Agreement. This would include

Verizon performing certain ongoing vegetation management activities in the areas in which Verizon has a maintenance commitment. Additionally, Verizon would be reimbursing the Company for vegetation management expenses associated with major storm related activities. The Company has indicated that these negotiations are currently confidential, but are ongoing. This issue should be addressed and resolved within the next year, so that both from a major storm cost and from the perspective of ongoing vegetation management cost, Verizon offsets, either through payment or through its own work efforts, a portion of the Company's vegetation management cost such that the electric ratepayers are not paying for vegetation management benefits for the telecommunication customers. As an example, I have determined the Western Massachusetts Electric Company has billed and received payments from Verizon for storm related vegetation management. Although there has been no adjustment in this area in the FY 2014 ISR Plan, the Company should be on notice that such evaluations and appropriate adjustments are imminent in future ISR Plans, regardless of whether the Company brings it negotiations with Verizon to a successful conclusion. There are clearly certain costs that should be borne by the telecommunications customers of Verizon, and not the electric ratepayers of the Company. We recommend the Company have an adjustment for these costs in its FY 2015 Electric ISR Plan. That will give the Company adequate time to resolve the dispute with Verizon.

G. <u>Inspection & Maintenance Category</u>

I started my evaluation of the Company's Inspection and Maintenance ("I&M") Program by reviewing in detail all of the Capital Projects and the O&M Expenses included in the

November 5, 2012 Initial ISR Plan submitted to the Division. There is no longer a redundancy associated with the transition from the prior programs to the I&M Program and its processes, which began in FY 2012. The Feeder Hardening and reliability programs that were an outgrowth of the Reliability Assessment Project from 2001 will be concluded in FY 2014. The three major areas are the new I&M Program, the Potted Porcelain Cutout Replacement Program, and the completion of the Feeder Hardening Program, which only incorporate $200,000 in FY 2014.

The most significant addition in the I&M program is under the Operation and Maintenance expenses. Docket No. 4237 for the Contact Voltage Mobile Testing Program resulted in hearings and evaluation in which I provided filed testimony. A subsequent RFP process was completed by the Company. I have reviewed the RFP process, and prepared a letter response and recommendation as it relates to the Company's final report concerning the RFP process results and associated costs. There was subsequent hearing, letters from Intervenors, and a lengthy response by the Company to the Power Service Company letter. The Commission issued an order in Docket No. 4237. The Company has incorporated the new Contact Voltage Mobile Testing Program in its FY 2014 I&M expenses. These costs have been incorporated in the I&M program expense category, and are a statutory requirement. This is the major component that accounts for increase in the I&M program expenses over historical levels. The other expense line items are consistent with the current programs as have been developed in their early stages.

Inspection and Maintenance Proposed FY 2014 Spending

SPENDING RATIONALE	BUDGET CLASS	Initial FY2014 Proposed Budget (11-5-12)	PowerServices Adjustments	Filed FY2014 Proposed Budget (12-28-12)
Inspection and Maintenance Program	**Capital (1)**	8,515,000	-	8,515,000
	Opex related to Capex	1,286,300	-	1,286,300
	Inspections and Repair - Related Costs[2]	2,492,700	-	2,492,700
Subtotal Operation and Maintenance Expenses		**3,779,000**	**-**	**3,779,000**
Inspection and Maintenance Program Total		**12,294,000**	**-**	**12,294,000**

(1) The capital costs shown here are included in the proposed $59.6 M capital plan.
(2) Includes contact voltage docket costs

<u>Overall</u>

The previous Chart 5 under the Introduction compares the Company's November 5, 2012 proposed capital expenditure levels to those the Division and the Company ultimately agreed upon, as reflected in the Company's Electric ISR Plan filed December 28, 2012 and the Company's Chart 5. The consensus ISR Plan is a nearly five percent (5%) reduction of $1,800,000 in the discretionary capital spending budget from the November 5, 2012 proposed level. The overall capital spending reduction was nearly seven percent (7%) or $4,400,000.

The analysis indicated the Company made the reductions in each category and specific projects as we recommended during our evaluation of its initial proposed ISR Plan budget submitted November 5, 2012. The Company made adjustments, as agreed upon with the Division, and incorporated additional discussion of each category to more fully explain the requirements for the FY 2014 Electric ISR Plan Proposed Budget in its Docket No. 4382 filing. During a subsequent review of the December 28, 2012 filing, an error was identified in Chart 2, Page 8 of 8 of the Inspection & Maintenance Program

Section, for the I&M Program Costs. The $8,614,000 should be $8,515,000. The Company has been made aware of this finding and is expected to correct it on the record.

III. CONCLUSION

The collaborative process between the Company and the Division resulted in a FY 2014 Electric ISR Plan which sets forth a capital budget, VM Program and I&M Program, and associated O&M activities which balance the need for safety and reliability with the efficient benefit/cost considerations. Appendix-3, Summary of Chart of Capital Outlays by Key Driver Category and Budget Classification, summarizes, by spending rationale (category) and individual budget class within each category, differences between the Company's initially proposed ISR Plan of November 5, 2012 and the resulting December 28, 2012 filing of the FY 2014 ISR Plan Proposal. The Statutory/Regulatory portions of the FY 2014 Proposal were adjusted for reasons previously discussed. Additional adjustments were achieved in the other capital and O&M categories through a cooperative process of balancing cost with safety and reliability. The new Contact Voltage Mobile Testing Program cost has also been incorporated in FY 2014. This is the first year for this statutory program, which is reflected in the Inspection and Maintenance Program Expenses. Appendix-3 reflects the initial budget request in the November filing and the adjustments, which resulted in the consensus with the Division and final Electric Infrastructure, Safety and Reliability Plan FY 2014 Proposal as filed on December 28, 2012.

There will be numerous challenges in the near term through FY 2016. While many of the same competing interests of safety, reliability, benefit to cost, and economic pressures will need to be considered going forward, the Division has established a number of important areas of consideration for the Company in establishment of future budgets. The substation flood related mitigation projects and substation capacity projects will potentially account for more than ten percent (10%) of the capital budget over FY 2015 and FY 2016. It will be critical to carefully evaluate the risk mitigation benefits associated with the flood related projects developed during the FY 2013 engineering studies and the substation capacity enhancements proposed in future ISR Plans. In order for the Division to have adequate time to evaluate this area, the Company should provide its plan, loading criteria, and load projections no later that the end of August of each year, which would be ahead of the delivery of the entire proposed ISR Plan.

I support the FY 2014 Capital Budget as proposed at $59,600,000 with a value for the capital placed into service in FY 2014, plus cost of removal at $9,545,000. I also support the FY 2014 proposed VM Program at $8,476,000 and the I&M Program Operations and Maintenance Expenses at $3,779,000 (which includes the Contact Voltage Mobile Testing Program).

Furthermore, I am a proponent for an annual adjustment process for the categories of Statutory/Regulatory and Damage/Failure.

Additional Recommendations

1. National Grid should be required to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management Program for the Division's review prior to the Electric Infrastructure, Safety, and Reliability Plan FY 2015 Proposal is submitted. These cost-benefit analyses shall incorporate, as a minimum, the parameters outlined earlier in this report.

2. National Grid should submit its detailed substation capacity expansion plans, including load projections, at least 120 days prior to filing its FY 2015 Proposal in order to give the Division sufficient time to evaluate all of the options, considering the very capital intense nature of substation expansion and construction. This should be no later than the end of August 2013. Furthermore, it appears the Company will be planning significantly more dollars to be spent on substations over the next 5 years than they have historically spent. A meeting between the Company and Division focusing on this area of planning and expansion is advisable. It is recommended that, by the end of August of each year, the Company provide to the Division the Capacity Relief Plan to include the proposed and alternate plans for additional substations and increased substation capacity. The reason for this recommendation of these planning components to be provided in advance of each year's ISR Plan is to give the Division adequate time to evaluate all of the alternatives and options, and the extensive impact of these very expensive substations, which generally have a two to four year budget cycle from start to finish.
3. National Grid should submit its Metal-Clad Switchgear replacement program cost-benefit analysis to the Division no later than August 31, 2013, in order to give the Division adequate time to evaluate this long term capital intense program.
4. Lastly, the Company should submit its final resolution of the Verizon vegetation management negotiations prior to its next ISR Plan.

This concludes my Report on the Electric Infrastructure, Safety and Reliability Plan FY 2014 Proposal as filed by National Grid on December 28, 2012.

AFFIDAVIT OF GREGORY L. BOOTH, PE

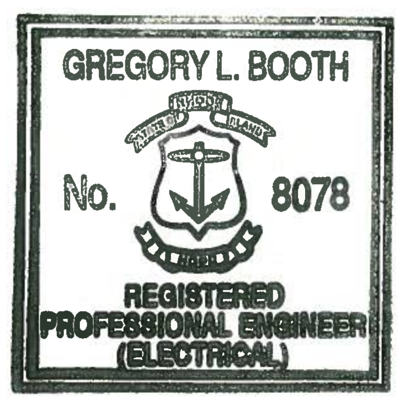
Gregory L. Booth, does hereby depose and say as follows:

I, Gregory L. Booth, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 28th day of February, 2013.

Gregory L. Booth

I hereby certify this document was prepared by me or under my direct supervision. I also certify I am a duly registered professional engineer under the laws of the State of Rhode Island, Registration No. 8078.



Gregory L. Booth, PE

APPENDIX 1

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

FYI 2014 ISR PLAN

DISCUSSION ITEMS FOR

NATIONAL GRID

1. **Statutory/Regulatory**
    a. **Manner adjustments up or down were accounted for from last year**
    b. **Explain ShunPike Sub and any CIAC and if $0.65 M completes the project**
    c. **Are all CIAC from joint pole users and DOT treated the same and incorporate and how**
    d. **How has the continued economic down turn been reflected in the service extension and service upgrade costs. Spending associated with New Business- Commercial has trended lower since 2009; however it is projected above the FY2010 level.**
    e. **How has the loss of customers and homes from hurricane Sandy been reflected in this estimate**
    f. **Explain the expenditures associated with third party attachments. What costs are reimbursed by other companies and in what cases are costs the sole responsibility of the Company?**
2. **Damage/Failure**
    a. **Explain why hurricanes Irene and Sandy and the October 2011 storm do not reduce the expenditure in this category**
    b. **Explain the overall percentage increase in damage/failure specific spending from historical levels**
    c. **Discuss any expenditures that are included within this category that are associated with the I&M program**
3. **Contact Voltage Program**
    a. **Explain why the Docket 4237 mobile elevated voltage testing is not included in this category**
4. **Asset Condition**
    a. **Explain the level of increase justifications**
    b. **Explain the difference in the Underground and URD Cable Strategies. What statistical information can the Company provide detailing the frequency, cost per instance, and outage minutes associated with line sections and customers that are affected by URD failures? In the previous three years what has been the associated spending for URD cable mitigation?**
    c. **Discussdetails of theURD Strategy including whether cable failures are found using a “thumper” or “scope” and if the cables have bare concentric neutrals or a separate**

neutral cable. What level of neutral loss has been detected? Why has the replacement program been based on application after 3 failures in the same cable section? Explain the typical section length.

   d. **What is the distribution substation battery replacement program expected total budget and schedule to begin and complete work? Will work be completed in FY2013 since $430,000 has already been allocated to this purpose?**
   e. **Has a metalclad switchgear replacement program study and cost benefit analysis been completed? If it has, provide a copy. If it has not, will one be completed before any action is taken? How has this been incorporated into the flood mitigation plan?**
   f. **Is the construction work for the Merton 512 metalclad replacement construction phase included in this FY2014 plan?**
   g. **How much has been spent on "SmartGrid" implementation and what was the definitive benefit during Hurricane Irene or Sandy in reducing outage duration.**
   h. **Discuss the purpose and use of the proposed $730,000 Spare Substation Transformer and how this differs from previous spare transformer projects**
   i. **Has a spare mobile metalclad station been considered as part of the flood mitigation and storm program preparedness?**
   j. **Provide a detailed explanation of the Network Arc Flash Program mitigation strategy and why it is necessary since the 2012 NESC has reduced the incident energy levels expected from what was expected under the 2007 NESC and software calculations using IEEE 1584.**
   k. **What alternate plans were considered for the Eldred Station rebuild? In the event of a station loss at Clarke Street substation, how will the modular feeders be utilized to backfeed customer load?**

5. **Non-Infrastructure (No questions)**
6. **System Capacity and Performance**
   a. **Discuss the increase in distribution transformer upgrades for FY2014**
   b. **Discuss Load Relief projects and justifications and why necessary considering the lack of load growth. What is the Load Relief Project forecast for stations beyond FY2014?**
   c. **Explain how reducing the number of circuits results in increased capacity and reduced reliability.**
   d. **What type of model was used for the distribution system analysis and provide a copy of the before improvements and after improvements models?**
   e. **Provide the per circuit historical analysis.**
   f. **Discuss progress on Feeder Hardening project and its projected conclusion**
   g. **Explain why an aggressive beaker replacement program is required particularly in light of many other utilities continuing to maintain the older oil technology breakers**
7. **Flood Mitigation**
   a. **Discuss the status of the finalization of the Flood Mitigation study and summarize the final cost impact.**
   b. **Discuss the latest revisions to the plan.**

   c. **Explain why retiring Westerly Substation and moving that load to Hopkinton and Langworthy Substations will cost $10,500,000.**

8. **Vegetation Management**
   a. **Explain why Hurricane Irene and Sandy tree work did not eliminate most Hazard tree issues**
   b. **Explain why the same generic hazard tree economic benefit discussion is in the plan and there is not specific detailed data now available for support**
   c. **Explain why Hurricane Irene and Sandy tree clearing efforts did not reduce cycle trimming requirements**
   d. **Discuss how you propose collecting Vegetation Management expenses from Verizon pursuant to Commission Order on negotiations with the Division**
   e. **Explain justification for an increased level of VM costs in 2014 from historical periods**
   f. **Discuss how the FY2012 Sub-T spending is higher than FY2010, FY2011, and forecasted FY2013 if both the sideline and floor trimming miles/acres indicate the lightest of years?**
   g. **Explain the additional costs in the base EHTM program for FY2014 over prior years (excluding the one-time EHTM Irene budget for 2013). How will these additional dollars be directed?**
9. **Inspection and Maintenance Program**
   a. **Explain current progress on transition to new I&M program**
10. **Tunk Hill Reliability Project**
    a. **What other options to this project were considered?**
    b. **What is the economic benefit associated with spending $1,000,000 for only 800 customers**
11. **Volt/Var Management Project**
    a. **Has an economic benefit analysis been completed? If yes, provide a copy.**
    b. **Why is the present VAR support on the system not performing in an economic manner?**
    c. **Why has an RFP and competitive consideration not been given to other Volt/Var vendors? If it has been, provide the RFP and bids.**
12. **Storm Fund**
    a. **Discuss how the storm fund should be changed to reflect a more frequent severe storm occurrence.**
13. **Verizon JOA**
    a. **Begin an open dialog on how to bring Verizon to the table to discuss cost recovery particularly on Vegetation Management**

APPENDIX 2

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2006 Budget	FY 2006 Actual	FY 2007 Budget	FY 2007 Actual	FY 2008 Budget	FY 2008 Actual
Statutory/ Regulatory	3rd Party Attachments	-	362,916	-	75,680	280,000	(123,199)
	Distributed Generation						
	Land and Land Rights - Dist	180,000	199,978	180,000	244,275	230,000	313,141
	Meters – Dist	1,976,000	1,609,398	1,900,000	1,748,581	1,950,000	2,194,959
	New Business - Commercial	6,192,000	6,178,305	4,425,000	7,782,725	7,210,000	7,602,534
	New Business - Residential	4,500,000	5,111,949	4,200,000	6,564,788	5,900,000	4,951,161
	Outdoor Lighting - Capital	400,000	523,859	400,000	573,758	1,000,000	712,535
	Outdoor Lighting - Capital MV	-	-	-	-	-	-
	Public Requirements	3,814,000	4,393,841	3,297,500	(790,093)	3,010,000	1,640,703
	Transformers & Related Equipment	3,240,000	4,504,947	3,500,000	4,812,334	5,050,000	6,595,658
Statutory/Regulatory Total		**20,302,000**	**22,885,193**	**17,902,500**	**21,012,048**	**24,630,000**	**23,887,492**
Damage/ Failure	Damage/ Failure	3,250,000	7,655,568	4,550,000	6,764,097	5,650,000	7,266,897
	Major Storms – Dist	-	609,088	-	678,175	10,000	375,380
Damage/Failure Total		**3,250,000**	**8,264,656**	**4,550,000**	**7,442,272**	**5,660,000**	**7,642,277**
Subtotal Statutory/Regulatory - Damage/Failure		**23,552,000**	**31,149,849**	**22,452,500**	**28,454,320**	**30,290,000**	**31,529,769**
Asset Condition	Woonsocket & Related	-	-	-	-	1,014,000	80,639
	Asset Replacement	9,323,000	5,828,465	8,241,000	8,314,885	8,631,000	12,381,390
	Asset Replacement - I&M (NE)	-	-	400,000	28,022	300,000	20,727
	Substation Capital - Dist	-	-	-	-	-	-
	Safety	-	-	-	-	75,000	76,680
	Flood Damage Avoidance Engineering Studies						
Asset Condition Total		**9,323,000**	**5,828,465**	**8,641,000**	**8,342,907**	**10,020,000**	**12,559,436**
Non-Infrastructure	Corporate/Admin/General	-	(3,136,053)	-	2,441,291	-	(60,904)
	Facilities	693,000	742,137	890,000	563,836	-	121,166
	General Equipment	100,000	54,233	100,000	12,601	75,000	324,847
	Telecommunications Capital - Dist	-	143,386	-	23,333	-	-
Non-Infrastructure Total		**793,000**	**(2,196,297)**	**990,000**	**3,041,061**	**75,000**	**385,109**
System Capacity and Performance	Coventry & Related	-	-	-	-	-	4,345
	Hopkinton & Related	-	-	-	-	-	372
	Newport & Related	-	394	1,155,000	4,139	1,215,000	305,411
	West Warwick & Related	-	-	-	-	-	-
	Load Relief	5,964,000	7,306,395	4,648,000	6,694,784	5,030,000	3,486,228
	Reliability	2,922,500	3,022,794	5,745,000	3,529,889	5,104,000	5,446,383
	Reliability - FEEDER HARDENING	1,390,000	650,810	1,413,500	1,316,796	1,085,000	4,315,685
System Capacity and Performance Total		**10,276,500**	**10,980,393**	**12,961,500**	**11,545,608**	**12,434,000**	**13,558,424**
Total Electric Distribution		**43,944,500**	**45,762,410**	**45,045,000**	**51,383,896**	**52,819,000**	**58,032,738**
	Less: Facilities(where reported)	693,000	742,137	890,000	563,836		121,166
Grand Total		43,251,500	45,020,273	44,155,000	50,820,060	52,819,000	57,911,572
Vegetation Management Program	Cycle Trimming						4,141,000
	Post Irene EHTM						
	Hazard Tree						721,000
	Sub-T						294,000
	Police/Flagman Detail						340,000
	All Other Activities						1,134,000
Vegetation Management Program Total		-	-	-	-	-	**6,630,000**
Inspection and Maintenance Program	Operation and Maintenance Expenses:						
	Opex related to Capex						
	Repair - Related Costs						
	Inspections - Related Costs 2						
Inspection and Maintenance Program Total		-	-	-	-	-	-

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2009 Budget	FY 2009 Actual	FY 2010 Budget	FY 2010 Actual	FY 2011 Budget	FY 2011 Actual
Statutory/	3rd Party Attachments	208,000	873,018	306,000	780,847	620,000	(909,712)
Regulatory	Distributed Generation						
	Land and Land Rights - Dist	291,200	310,128	326,000	274,560	309,000	281,215
	Meters – Dist	2,101,000	2,135,191	2,690,000	2,042,048	2,040,000	2,214,951
	New Business - Commercial	5,691,500	6,993,422	5,801,000	4,705,078	5,550,000	4,286,660
	New Business - Residential	5,512,000	2,856,774	2,699,000	3,256,239	3,750,000	3,529,650
	Outdoor Lighting - Capital	1,001,200	1,236,779	945,000	941,164	680,000	411,364
	Outdoor Lighting - Capital MV	350,000	-	300,000	61,933	-	
	Public Requirements	3,906,968	1,465,029	4,126,000	3,121,260	3,810,000	1,539,416
	Transformers & Related Equipment	4,960,800	5,301,415	6,533,000	4,128,756	4,255,000	3,277,796
Statutory/Regulatory Total		**24,022,668**	**21,171,756**	**23,726,000**	**19,311,885**	**21,014,000**	**14,631,340**
Damage/	Damage/ Failure	6,496,000	7,488,952	7,419,000	9,143,559	8,925,000	8,330,840
Failure	Major Storms – Dist	100,000	856,490	500,000	(112,426)	440,000	4,863,261
Damage/Failure Total		**6,596,000**	**8,345,442**	**7,919,000**	**9,031,133**	**9,365,000**	**13,194,101**
Subtotal Statutory/Regulatory - Damage/Failure		**30,618,668**	**29,517,198**	**31,645,000**	**28,343,018**	**30,379,000**	**27,825,441**
Asset	Woonsocket & Related	2,650,000	57,883	2,108,000	1,043,789	6,080,000	
Condition	Asset Replacement	7,050,732	10,793,745	10,847,000	11,530,572	721,000	5,604,107
	Asset Replacement - I&M (NE)	325,000	112,553	1,298,000	490,942	400,000	226,693
	Substation Capital - Dist	-	-	-	-	-	-
	Safety	65,000	(22,943)	-	-	-	-
	Flood Damage Avoidance Engineering Studies						
Asset Condition Total		**10,090,732**	**10,941,238**	**14,253,000**	**13,065,303**	**7,201,000**	**5,830,800**
Non-	Corporate/Admin/General	-	(3,464)	-	(1,238,810)	-	645,055
Infrastructure	Facilities	-	134,036	-	256,800	-	
	General Equipment	67,600	154,236	161,000	391,872	200,000	60,548
	Telecommunications Capital - Dist	175,000	-	7,000	-	485,000	
Non-Infrastructure Total		**242,600**	**284,808**	**168,000**	**(590,138)**	**685,000**	**705,603**
System	Coventry & Related	950,000	89,324	1,128,000	558,222	300,000	80,307
Capacity and	Hopkinton & Related	150,000	96,615	645,000	547,535	200,000	185,856
Performance	Newport & Related	950,000	715,163	5,731,000	2,926,839	1,500,000	2,333,100
	West Warwick & Related	-	-	195,000	114,900	450,000	15,829
	Load Relief	4,335,500	5,988,143	6,780,000	4,650,580	1,958,000	3,396,843
	Reliability	5,667,500	3,878,186	3,641,000	5,768,069	2,214,000	2,798,644
	Reliability - FEEDER HARDENING	4,654,000	3,828,491	4,314,000	2,888,145	2,013,000	1,948,135
System Capacity and Performance Total		**16,707,000**	**14,595,922**	**22,434,000**	**17,454,290**	**8,635,000**	**10,758,714**
Total Electric Distribution		**57,659,000**	**55,339,166**	**68,500,000**	**58,272,473**	**46,900,000**	**45,120,558**
	Less: Facilities(where reported)		134,036		256,800		
Grand Total		**57,659,000**	**55,205,130**	**68,500,000**	**58,015,673**	**46,900,000**	**45,120,558**
Vegetation	Cycle Trimming		5,574,000		4,552,000		2,881,000
Management	Post Irene EHTM						
Program	Hazard Tree		757,000		709,000		283,000
	Sub-T		436,000		302,000		475,000
	Police/Flagman Detail		187,000		241,000		105,000
	All Other Activities		903,000		1,078,000		1,085,000
Vegetation Management Program Total		**-**	**7,857,000**	**-**	**6,882,000**	**-**	**4,829,000**
Inspection	Operation and Maintenance Expenses:						
and	Opex related to Capex						
Maintenance	Repair - Related Costs						
Program	Inspections - Related Costs 2						
Inspection and Maintenance Program Total		**-**	**-**	**-**	**-**	**-**	**-**

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY 2012 Budget	FY 2012 Actual	FY 2013 Budget	(1) FY 2013 Forecast	(2) FY 2014 Proposed
Statutory/ Regulatory	3rd Party Attachments	641,000	463,848	705,000		514,000
	Distributed Generation					162,000
	Land and Land Rights - Dist	321,000	185,520	297,000		190,000
	Meters – Dist	1,803,000	1,496,949	1,815,000		1,752,000
	New Business - Commercial	6,157,500	3,390,872	5,950,000		4,300,000
	New Business - Residential	3,917,000	2,833,259	3,304,000		3,025,000
	Outdoor Lighting - Capital	718,000	495,328	571,000		537,000
	Outdoor Lighting - Capital MV	300,000		-		-
	Public Requirements	3,968,000	1,134,582	3,709,000		2,599,000
	Transformers & Related Equipment	3,811,000	3,074,796	3,655,000		3,430,000
Statutory/Regulatory Total		**21,636,500**	**13,075,154**	**20,006,000**	**12,306,000**	**16,509,000**
Damage/ Failure	Damage/ Failure	9,245,000	9,573,923	9,772,000		9,375,000
	Major Storms – Dist	460,000	3,418,936	650,000		675,000
Damage/Failure Total		**9,705,000**	**12,992,859**	**10,422,000**	**9,776,000**	**10,050,000**
Subtotal Statutory/Regulatory - Damage/Failure		**31,341,500**	**26,068,013**	**30,428,000**	**22,082,000**	**26,559,000**
Asset Condition	Woonsocket & Related	5,005,000		825,000		-
	Asset Replacement	4,732,050	9,766,995	8,583,000		11,377,000
	Asset Replacement - I&M (NE)	1,381,000	553,104	1,250,000		8,515,000
	Substation Capital - Dist	-	-	-		-
	Safety	-	-	-		350,000
	Flood Damage Avoidance Engineering Studies	1,200,000	1,200,000	1,205,000		-
Asset Condition Total		**12,318,050**	**11,520,099**	**11,863,000**	**8,131,000**	**20,242,000**
Non-Infrastructure	Corporate/Admin/General	-	117,838	-		-
	Facilities	-	-	-		-
	General Equipment	278,000	148,707	186,000		105,000
	Telecommunications Capital - Dist	-	-	150,000		150,000
Non-Infrastructure Total		**278,000**	**266,545**	**336,000**	**1,808,000**	**255,000**
System Capacity and Performance	Coventry & Related	1,000,000		975,000		-
	Hopkinton & Related	800,000		800,000		-
	Newport & Related	720,000		450,000		-
	West Warwick & Related	520,000		325,000		-
	Load Relief	6,492,920	8,836,739	5,576,000		10,396,500
	Reliability	5,199,430	2,554,262	4,287,000		1,947,500
	Reliability - FEEDER HARDENING	3,230,100	2,564,239	1,500,000		200,000
System Capacity and Performance Total		**17,962,450**	**13,955,240**	**13,913,000**	**15,408,000**	**12,544,000**
Total Electric Distribution		**61,900,000**	**51,809,897**	**56,540,000**	**47,429,000**	**59,600,000**
	Less: Facilities(where reported)					
Grand Total		**61,900,000**	**51,809,897**	**56,540,000**	**47,429,000**	**59,600,000**
Vegetation Management Program	Cycle Trimming	5,902,000	5,451,000	5,150,000	5,150,000	5,230,000
	Post Irene EHTM			367,000		
	Hazard Tree	1,811,000	806,000	750,000	1,117,000	750,000
	Sub-T	267,000	392,000	290,000	290,000	724,000
	Police/Flagman Detail	585,000	461,000	488,000	750,000	525,000
	All Other Activities	1,261,000	1,066,000	1,211,000	1,211,000	1,247,000
Vegetation Management Program Total		**9,826,000**	**8,176,000**	**8,256,000**	**8,518,000**	**8,476,000**
Inspection and Maintenance Program	Operation and Maintenance Expenses:	-	-	-	-	-
	Opex related to Capex	1,725,285	1,316,275	1,476,500	1,335,000	1,286,300
	Repair - Related Costs	609,000	-	609,000	609,000	1,722,700
	Inspections - Related Costs 2	144,945	149,609	185,400	185,400	770,000
Inspection and Maintenance Program Total		**2,479,230**	**1,465,884**	**2,270,900**	**2,129,400**	**3,779,000**

Updated: 12/17/12

(1) FY2013 Forecast- Updated- Second Quarter Ending Sept 30, 2012- 11-30-12
(2) FY2014- FY2018- Updated- Attachment DIV 1-6 (General) FY 2014 Electric Infrastructure, Safety, and Reliability Plan- Responses to Division's Data Requests – Set 1- 12-7-12

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	(2) FY 2015 Proposed	(2) FY 2016 Proposed	(2) FY 2017 Proposed	(2) FY 2018 Proposed
Statutory/ Regulatory	3rd Party Attachments	529,000	545,000	561,000	578,000
	Distributed Generation				
	Land and Land Rights - Dist	296,000	314,000	333,000	353,000
	Meters – Dist	1,956,000	2,077,000	2,211,000	2,358,000
	New Business - Commercial	4,961,000	4,889,000	5,225,000	5,576,000
	New Business - Residential	3,563,000	3,791,000	4,029,000	4,282,000
	Outdoor Lighting - Capital	556,000	576,000	595,000	615,000
	Outdoor Lighting - Capital MV	-	-	-	-
	Public Requirements	2,964,000	2,318,000	2,489,000	2,565,000
	Transformers & Related Equipment	3,992,000	4,151,000	4,358,000	4,500,000
Statutory/Regulatory Total		**18,817,000**	**18,661,000**	**19,801,000**	**20,827,000**
Damage/ Failure	Damage/ Failure	9,776,000	10,093,000	10,404,000	10,724,000
	Major Storms – Dist	700,000	725,000	750,000	775,000
Damage/Failure Total		**10,476,000**	**10,818,000**	**11,154,000**	**11,499,000**
Subtotal Statutory/Regulatory - Damage/Failure		**29,293,000**	**29,479,000**	**30,955,000**	**32,326,000**
Asset Condition	Woonsocket & Related	-	-	-	-
	Asset Replacement	13,571,000	10,888,000	13,762,000	12,481,000
	Asset Replacement - I&M (NE)	10,655,000	10,960,000	11,265,000	11,570,000
	Substation Capital - Dist	-	-	-	-
	Safety	675,000	650,000	650,000	687,000
	Flood Damage Avoidance Engineering Studies				
Asset Condition Total		**24,901,000**	**22,498,000**	**25,677,000**	**24,738,000**
Non-Infrastructure	Corporate/Admin/General	-	-	-	-
	Facilities	-	-	-	-
	General Equipment	111,000	117,000	122,000	128,000
	Telecommunications Capital - Dist	150,000	150,000	150,000	150,000
Non-Infrastructure Total		**261,000**	**267,000**	**272,000**	**278,000**
System Capacity and Performance	Coventry & Related	-	-	-	-
	Hopkinton & Related	-	-	-	-
	Newport & Related	-	-	-	-
	West Warwick & Related	-	-	-	-
	Load Relief	19,271,000	23,188,000	16,485,000	16,052,000
	Reliability	6,274,000	4,568,000	4,611,000	4,606,000
	Reliability - FEEDER HARDENING	-	-	-	-
System Capacity and Performance Total		**25,545,000**	**27,756,000**	**21,096,000**	**20,658,000**
Total Electric Distribution		**80,000,000**	**80,000,000**	**78,000,000**	**78,000,000**
	Less: Facilities(where reported)				
Grand Total		80,000,000	80,000,000	78,000,000	78,000,000
Vegetation Management Program	Cycle Trimming				
	Post Irene EHTM				
	Hazard Tree				
	Sub-T				
	Police/Flagman Detail				
	All Other Activities				
Vegetation Management Program Total		-	-	-	-
Inspection and Maintenance Program	Operation and Maintenance Expenses:				
	Opex related to Capex				
	Repair - Related Costs				
	Inspections - Related Costs 2				
Inspection and Maintenance Program Total		-	-	-	-

Updated: 12/17/12

(2) FY2014- FY2018- Updated- Attachment DIV 1-6 (General) FY 2014 Electric Infrastructure, Safety, and Reliability Plan- Responses to Division's Data Requests – Set 1- 12-7-12

APPENDIX 3

Adjustment Summary Chart- FY 2014 ISR

Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	Initial FY2014 Proposed Budget (11-5-12)		PowerServices Adjustments	PowerServices FY2014 Proposed Budget (12-28-12)
Statutory/ Regulatory	3rd Party Attachments	514,000			514,000
	Distributed Generation	162,000			162,000
	Land and Land Rights - Dist	280,000	(1)	(90,000)	190,000
	Meters – Dist	1,837,000	(1)	(85,000)	1,752,000
	New Business - Commercial	4,996,000	(1)	(696,000)	4,300,000
	New Business - Residential	3,348,000	(1)	(323,000)	3,025,000
	Outdoor Lighting - Capital	537,000			537,000
	Outdoor Lighting - Capital MV	-			-
	Public Requirements	3,599,000	(1)	(1,000,000)	2,599,000
	Transformers & Related Equipment	3,836,000	(1)	(406,000)	3,430,000
Statutory/Regulatory Total		**19,109,000**		**(2,600,000)**	**16,509,000**
Damage/ Failure	Damage/ Failure	9,375,000			9,375,000
	Major Storms – Dist	675,000			675,000
Damage/Failure Total		**10,050,000**	**-**	**-**	**10,050,000**
Subtotal Statutory/Regulatory - Damage/Failure		**29,159,000**	**-**	**(2,600,000)**	**26,559,000**
Asset Condition	Woonsocket & Related	-		-	-
	Asset Replacement	11,877,000	(3)	(500,000)	11,377,000
	Asset Replacement - I&M (NE)	8,515,000			8,515,000
	Substation Capital - Dist	-			-
	Safety	650,000	(5)	(300,000)	350,000
	Flood Related Capital and Studies	-			-
Asset Condition Total		**21,042,000**		**(800,000)**	**20,242,000**
Non-Infrastructure	Corporate/Admin/General	-			-
	Facilities	-			-
	General Equipment	105,000			105,000
	Telecommunications Capital - Dist	150,000			150,000
Non-Infrastructure Total		**255,000**	**-**	**-**	**255,000**
System Capacity and Performance	Coventry & Related	-			-
	Hopkinton & Related	-			-
	Newport & Related	-			-
	West Warwick & Related	-			-
	Load Relief	10,396,500			10,396,500
	Reliability	2,947,500	(2)	(1,000,000)	1,947,500
	Reliability - FEEDER HARDENING	200,000			200,000
System Capacity and Performance Total		**13,544,000**	**(2)**	**(1,000,000)**	**12,544,000**
Grand Total		**64,000,000**		**(4,400,000)**	**59,600,000**

Vegetation Management Program	Cycle Trimming	5,230,000			5,230,000
	Post Irene EHTM	-			-
	Hazard Tree	950,000	(4)	(200,000)	750,000
	Sub-T	724,000			724,000
	Police/Flagman Detail	525,000			525,000
	All Other Activities	1,247,000			1,247,000
Vegetation Management Program Total		**8,676,000**	**(4)**	**(200,000)**	**8,476,000**

Inspection and Maintenance Program	Operation and Maintenance Expenses:				-
	Opex related to Capex	1,286,300			1,286,300
	Inspections and Repair - Related Cost	2,492,700			2,492,700
Inspection and Maintenance Program Tota		**3,779,000**	**-**	**-**	**3,779,000**

Updated: 01/30/2013

(1) Proposed Adjustments- National Grid Attachment DIV 1-5 (Statutory/Regulatory) FY2014 ISR- Responses to Division's Data Requests- Set 1, Page 1 of 1

(2) Proposed Adjustment- Volt/Var Management- PPM 19782- Program reduced from $1.5M to $500k and will be discussed further after initial engineering study is completed on the proposed six(6) feeders.

(3) Proposed Adjustment- IE_OS URD Cable Replacement- C31400- Program reduced from $2M to $1.5M.

(4) Proposed Adjustment- Vegetation Management EHTM

(5) Proposed Adjustment- National Grid conference call on 12/20/12- Arc Flash Program spending will be implemented differently than initially estimated, with the probability of taking 6 years rather than the 5 years originally anticipated.