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. 4539 Docket No. 4539
RE: FY 2016 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

March 3, 2015

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. 4539

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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-two (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, 4218, 4237, 4307, 4360, 4382, 4473, 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, 4307, 4382, and 4473.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT IN OTHER JURISDICTIONS?

A. I have testified before the FERC and numerous state commissions, including in Delaware, Florida, Maryland, Massachusetts, North Carolina, Pennsylvania, and Virginia.

Q DOES ANY OF YOUR TESTIMONY AND DO ANY OF THE ORDERS ISSUED IN THESE OTHER JURISDICTIONS RELATE TO YOUR RCOMMENDATIONS BEING PRESENTED ON BEHALF OF THE DIVISION?

A. As it relates to my recommendations to this Commission, I have filed testimony and provided live testimony in Massachusetts and Virginia on multiple occasions which addressed pole attachment by communication companies and reimbursement for cost incurred by the electric utility. My testimony and the Orders from these proceedings to which I refer were regarding telecommunication companies providing just and reasonable compensation to electric utilities for certain benefits the communication company receives from joint ownership, or joint use, of electric poles and rights-of-way. Specifically applicable to this Docket, one of my recommendations was that the Company recovery for vegetation management costs from Verizon be at an appropriate level consistent with the existing Joint Ownership Agreement. The Massachusetts Department of Public Utilities has taken a comparable position in storm reimbursement dockets, including National Grid Docket No. DPU 11-56. I will discuss my recommendations concerning vegetation management in further detail under Section III of my Pre-Filed Direct Testimony and in *Exhibit GLB-1*.

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 National Grid's Proposed FY 2016 Electric Infrastructure, Safety and Reliability Plan dated October 10, 2014 ("ISR Plan"). My testimony will briefly summarize the collaborative process between the Division and National Grid, which resulted in the proposed ISR Plan filed December 23, 2014, together with summarizing the details of *Exhibit GLB-1* and my recommendations. My testimony and *Exhibit GLB-1* will also address the one area, vegetation management, in which a consensus could not be achieved.

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 23, 2014 IN THIS DOCKET?

A. Yes.

- First, at an August 25, 2014 meeting with PowerServices and the Division, National Grid provided pre-plan filing materials including reports and evaluations required of National Grid in advance of the FY 2106 filing.
- Second, National Grid submitted an initial FY 2016 ISR Plan Proposal on October 10, 2014 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.
- Third, I prepared two separate data requests on October 30, 2014 and November 10, 2014. National Grid submitted the majority of responses to the data requests as Responses to the Division Data Requests-Set 1 on November 14, 2014 and Responses to the Division's Data Requests-Set 2 on November 19, 2014. National Grid provided remaining responses as information became available, with the last item received on January 14, 2015 (Pawtucket Area Study).
- Fourth, PowerServices, the Division, and National Grid met on November 20, 2014 to discuss each spending category in detail, review responses to data requests, and clarify additional outstanding information.
- Fifth, PowerServices and National Grid held conference calls on December 3, 2014 and December 10, 2014 to discuss in detail the proposed work in each ISR category. National Grid provided additional or clarifying information related to several

programs and PowerServices' presented preliminary recommendations for adjustments to the ISR Plan. Agreement was reached on several spending categories

- Sixth, the Division, PowerServices, and National Grid held a second conference on December 10, 2014 to discuss steps that the Company had taken with Verizon to recover Vegetation Management costs.
- Seventh, PowerServices and the Company held a conference On December 17, 2014 to finalize proposed adjustments. Consensus was reached in each proposed category, excluding adjustments to Vegetation Management related to Verizon's cost responsibility.
- Lastly, throughout the process, National Grid was open to the Division's recommended adjustments with the exception of Vegetation Management. Subsequent detailed discussions between PowerServices, the Division, and National Grid were held to define a clear timeline and action items to resolve outstanding issues with Verizon, which resulted in the recommendations contained in my report.

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 23, 2014 filing:

SPENDING RATIONALE	INITIAL FY2016 (10-10-14)	POWERSERVICES ADJUSTMENTS	FILED FY2016 (12-23-14)
Customer Request/Public Requirements	$ 15,747,000	$ (100,000)	$ 15,647,000
Damage/Failure Total	$ 11,177,000	$ -	$ 11,177,000
Subtotal	***$ 26,924,000***	***$ (100,000)***	***$ 26,824,000***
Asset Condition	$ 27,153,000	$ (3,100,000)	$ 24,053,000
Non-Infrastructure	$ 275,000	$ -	$ 277,000
System Capacity and Performance	$ 22,148,000	$ -	$ 22,148,000
Subtotal	***$ 49,576,000***	***$ (3,100,000)***	***$ 46,476,000***
Grand Total	**$ 76,500,000**	**$ (3,200,000)**	**$ 73,300,000**

IV. COMMENTS ON WITNESS TESTIMONY

Q. HAVE YOU REVIEWED THE PRE-FILED TESTIMONY OF JAMES H. PATTERSON, JR. AND RYAN A. MOE?

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 Mr. Patterson and Mr. Moe accurately reflects the FY 2016 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. However, the pre-filed testimony does not address my ultimate recommendation regarding vegetation management expenditures. After extensive discussions with National Grid, I agreed that the level of proposed expenditures for the FY 2016 vegetation management plan were reasonable, however, I recommended an expected downward adjustment to account for Verizon's responsibility under the Joint Ownership Agreement. This downward adjustment applies to the level of cost recovery from the electric ratepayer and not to the ultimate amount of vegetation management activity necessary. 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.

Additionally, the testimony and ISR Plan fail to adequately address my recommendation for a comprehensive System Capacity Load Study and Long Range Plan prior to the inclusion of new major capital projects. My support of several new projects in the FY

2016 ISR Plan is conditioned upon the completion of this comprehensive study and plan, and, furthermore, my support for existing major projects is conditioned on National Grid providing more thorough project scopes, engineering analysis and detailed budgets. I discuss these requirements and applicable projects in depth in *Exhibit GLB -1*.

V. REPORT SUMMARY

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

A. The report contains an Introduction describing the overall process and summarizing the adjustments which resulted in a consensus for the FY 2016 ISR Plan Proposed Budget of $73,300,000 for capital items. National Grid proposed a Vegetation Management Program expense budget of $8,884,000, which did not reflect an anticipated reduction in the recovery from the electric ratepayers of $1,854,181 to account for Verizon's responsibility. Also, an I&M Program Operations & Maintenance expense budget of $3,333,000 is included. The *Exhibit GLB-1* report section on the Capital Investment Plan discusses in detail each major category: Customer Request/Public Requirements, (previously Statutory/Regulatory); Asset Condition; Non-Infrastructure; System Capacity and Performance; Vegetation Management; and Inspection and Maintenance expenses, outlining the issues considered, the adjustments proposed, and the reasoning for the adjustments as accepted by National Grid. A detailed summary chart contained in *Exhibit GLB-1* as Appendix-3 shows each Spending Rationale and Budget Class with the October 2014 initial proposed budget, our recommended adjustments, our recommended budget, and the December 23, 2014 Filed Proposed Budget which does not include the proposed vegetation management adjustment.

The report contains a conclusion which supports the FY 2016 ISR Plan Proposal Budget as filed by National Grid on December 23, 2014, with the exception of the level of vegetation management to be included in rates. The conclusion includes ten (10) recommendations for the capital investment portion of the ISR Plan, and a specific recommendation for the Division to initiate proceedings investigating Verizon's practices that compromise utility system safety and reliability and pose dangers to public safety. Additionally, the Division and the Company have reached an agreement on the detailed steps the Company will take in its efforts to recover the Vegetation Management expenses Verizon should be paying, along with remedying an outdated JOA.

VI. CONCLUSION

Q. DO YOU AND THE DIVISION SUPPORT THE NATIONAL GRID FY 2016 ELECTRIC ISR PLAN PROPOSAL FOR $73,300,000 IN BUDGETED CAPITAL EXPENDITURES, WITH $8,884,000 IN VEGETATION MANAGEMENT EXPENSES AND $3,333,000 IN INSPECTION AND MAINTENANCE EXPENSES?

A. We did not reach agreement on all cost components. Although we failed to reach an agreement on the Vegetation Management Expenses which would be borne by the electric ratepayers, we did agree to withhold an immediate adjustment based on the Company putting forth a definitive and meaningful set of action items, timeline and benchmarks to reach an agreement with Verizon for reimbursement of its cost sharing component. Based on the Company proceeding to aggressively implement the provisions of an agreement reached between the Division and the Company, the Division will support the vegetation management budget until it reviews the Company's actions prior to the rate reconciliation process.

Q. WHAT ARE THE RECOMMENDATIONS RELATED TO CAPITAL INVESTMENT YOU HAVE MADE IN YOUR REPORT *EXHIBIT GLB-1*?

A. The ten (10) recommendations related to capital investment 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 accelerate development of a System Capacity Load Study and develop a 10-year Long Range Plan as part of the FY 2018 ISR Plan in order to increase the level of support and transparency for the capital budget. This Long Range Plan is critical to the overall capital investment strategy for building and

maintaining a robust and reliable electric system. The Company shall submit a report with updates on modeling activities in addition to the proposed Long Range Plan (completed portions) at least 120 days prior to filing its FY 2017 ISR Plan Proposal, but in any event no later than August 31, 2015. This should be continued with each subsequent ISR Plan process.

2. National Grid shall revisit the scope and budget of the South Street substation project in the Asset Replacement category once the Providence short term study and preliminary engineering are complete, indicating findings in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015. The Company shall provide detailed design, identification of risks and mitigation strategies, and a refined budget for further evaluation.

3. National Grid shall limit FY 2016 expenses to preliminary engineering for the Southeast Substation project in the Asset Replacement category, and provide a detailed project scope, timeline and budget for further evaluation in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

4. National Grid shall limit FY 2016 expenses to system capacity studies and preliminary engineering for the East Bay Study and Jepson Substation projects in the System Capacity and Performance category until a 10-year Long Range Plan is complete, at which time the projects should be evaluated against the results of such plan.

5. National Grid shall evaluate cost effective alternatives for the Quonset Point project in the System Capacity and Performance category, and demonstrate that proposed solutions align with the industrial expansion timing and capacity needs.

The evaluation shall be provided in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

6. National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

7. National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long Range Plan in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

8. National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan, in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

9. National Grid shall continue 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 FY 2017 ISR Plan Proposal, but in any event no later than August 31, 2015.

10. National Grid shall continue to submit its Metal-Clad Switchgear replacement program cost-benefit analysis to the Division prior to submitting the Company's FY2017 ISR Plan Proposal, but in any event no later than August 31, 2015.

Q. WHAT ARE THE RECOMMENDATIONS RELATED TO VEGETATION MANAGEMENT YOU HAVE MADE IN YOUR REPORT *EXHIBIT GLB-1*?

A. Because National Grid has failed to demonstrate any meaningful progress or a cohesive plan intended to create substantive results in negotiations with Verizon, the Division and the Company have agreed to a set of action items with a timeline. I recommend that the Company fully cooperate with the Division in pursuing the provisions of this agreement.

Q. WHAT IS THE RECOMMENDATION FOR DIVISION ACTION YOU HAVE MADE IN YOUR REPORT *EXHIBIT GLB-1*?

A. I recommend the Division initiate a proceeding pursuant to its rights under Chapter 39-4-10 and 39-4-11 based on Verizon's unjust and unreasonable actions which constitute a violation of the National Electrical Safety Code. Verizon's practices and disregard for the NESC result in unsafe, dangerous, and improper utility operation and maintenance, creating conditions in which public safety is endangered.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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 3rd day of March, 2015.

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

EXHIBIT GLB-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 2016 Electric Infrastructure, Safety, and Reliability Plan
Docket No. 4539

March 3, 2015

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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 2016 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 2016 Electric Infrastructure, Safety, and Reliability Plan
Docket No. 4539

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I. INTRODUCTION

PowerServices, Inc. ("PowerServices"[1]) 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 2016 Proposal (the "ISR Plan" or "Plan") dated October 10, 2014, and the final Electric Infrastructure, Safety, and Reliability Plan FY 2016 Proposal dated December 23, 2014 and filed in Docket 4539. The evaluation followed the same process of analysis completed for the FY 2012, FY 2013, FY 2014 ISR and FY 2015 ISR Plans. This Report will include an explanation of the process for the initial ISR Plan proposal evaluations and collaborative efforts, resulting in a reduction of proposed FY 2016 capital spending in several areas, including Customer Request/Public Requirements[2], capital expenses for asset replacement, operation & maintenance ("O&M") expenses for an Inspection and Maintenance ("I&M") program, and "O&M" expenses for Vegetation Management ("VM"). The reductions were applied to the proposed spending levels in the Company's FY 2016 ISR Plan Proposal submitted to the Division October 10, 2014 and are reflected in the subsequent FY 2016 ISR Plan Proposal dated December 23, 2014. 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 2016 to be included in what is now the Company's filing of an Electric ISR Plan in Docket No. 4539. The

[1] For the purposes of this report, reference to "PowerServices", "I", and "my" are interchangeable.
[2] Previously called "Statutory/Regulatory"

Division and the Company did not agree on an adjustment, accounting for Verizon's responsibility for vegetation management to be netted against the Company's proposed FY 2016 budget.

The Company's initial proposed FY 2016 ISR Plan followed very closely the format and principals agreed to in previous Plans. The spending rationales were similar except for a modification to the "Statutory/Regulatory" category title which is now referenced as "Customer Request/Public Requirements". Most of the Company's budget line items were structurally similar to the previous Plans with modifications in the cost structure, and the Company generally met the guidelines used to reach agreement for the cost during the last evaluation process.

PowerServices has historically performed evaluations by reviewing the Company's pre-plan information along with the proposed ISR Plan. The pre-plan information traditionally included reliability reports, budget variance explanations, and cost benefit analysis for metalclad switchgear, Inspection and Maintenance, and Vegetation Management programs. My evaluation of the FY 2015 ISR recommended that the Company develop a 10-year Long Range Plan and submit additional reports and data in advance of the proposed FY 2016 ISR. The Rhode Island Public Utilities Commission[3] supported PowerServices' recommendations, and the Company provided supplemental pre-plan information, including detailed budgets for System Capacity and Performance and Asset Condition spending categories, along with area capacity studies since a comprehensive Long Range Plan had not been completed. An in-depth analysis of the pre-plan

[3] State of Rhode Island and Providence Plantation Public Utilities Commission Report and Order regarding National Grid Proposed FY 2015 ISR Plan under Docket 4473

information and each component of the proposed FY 2016 ISR Plan was undertaken. The evaluation and analysis process was performed, including the following procedures:

(1.) An August 25, 2014 meeting (Appendix-1 contains the Agenda for this meeting) was held between the Division, PowerServices, and the Company to discuss the planning process and the reports required of National Grid in advance of the FY 2106 ISR Plan filing ("Pre-Plan Information"),

(2.) On August 29, 2014, the Company provided the Division with the Pre-Plan Filing Documents for the FY 2016 ISR Plan,

(3.) On October 10, 2014, the Company filed the initial FY 2016 ISR Plan Proposal,

(4.) PowerServices evaluated the Pre-Plan Information and proposed ISR Plan and on October 30, 2014, provided Data Request No. 1,

(5.) On November 10, 2014, PowerServices provided Data Request No. 2,

(6.) On November 14 and November 20, 2014, the Company provided responses to Data Requests Nos. 1 and 2[4],

(7.) On November 20, 2014, representatives of the Division, PowerServices, and the Company met to discuss each spending category in detail, review responses to data requests, and clarify additional outstanding information,

(8.) On November 25, 2014, PowerServices provided the Company with a summary of the November 20th meeting to document outstanding items and request clarifying information,

[4] The Company provided the majority of available data, excluding reports that were in process.

(9.) On December 3, 2014, PowerServices and the Company held a conference call to discuss reliability metrics and the I&M program. PowerServices provided preliminary adjustments to the ISR Plan and requested additional information,

(10.) On December 9, the Company completed responses to outstanding data requests excluding system studies in progress,

(11.) On December 10, 2014, PowerServices and the Company held a conference call to discuss the preliminary evaluation and PowerServices' proposed adjustments. Agreement was reached on several spending categories with acknowledgement that system studies to support various projects would be provided when completed,

(12.) On December 10, 2014, a subsequent conference call with the Division, PowerServices, and the Company was held to discuss steps that the Company had taken with Verizon to recover Vegetation Management costs,

(13.) On December 17, 2014, PowerServices and the Company held a conference call to finalize proposed adjustments. Consensus was reached in each proposed category except for adjustments to Vegetation Management related to Verizon's cost responsibility,

(14.) On December 22, 2014, PowerServices, the Division and the Company discussed in detail the activities and issues related to vegetation management cost sharing in both Massachusetts and Rhode Island,

(15.) On December 23, 2014, the Company filed the final FY 2016 ISR Plan Proposal,

(16.) On January 14, 2014, the Company provided the Pawtucket Area Study, completed in December, in response to Data Request No. 1, (17.) On January 29, 2015, PowerServices, the Division and the Company held a conference call on Vegetation Management to discuss timelines and expected outcomes of Verizon negotiations, and

(18.) On February 12, 2015, the Company provided a simplistic statement for continued negotiations with Verizon.

(19.) On February 26, 2015, the Division and the Company agreed to a set of action items and timeline to address recovery of historical and future vegetation management expenses from Verizon, along with a process to remedy deficiencies in the JOA.

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 2016 which would have the support of the Division. This series of meetings, 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 formal data requests and responses referred to above were made part of the record through a filing of same by National Grid on January 20, 2015.

The structure of the FY 2016 ISR Plan filing closely followed the FY 2015 ISR Plan to the extent that the Company has included several of its historic annual programs. The Company continued to incorporate key changes noted in the prior filings, including migration of substation flood mitigation programs to an overall substation capacity enhancement and reliability program and incorporation of an Inspection & Maintenance Program to replace the phased out Feeder Hardening Program. The FY 2016 Plan continued the trend of significant discretionary spending levels for major construction projects in the System Capacity and Performance category budget, initially observed in the FY 2015 Plan. The magnitude of planned capital expenditures prompted expanded discussions and additional meetings than have occurred historically between the Company, the Division, and PowerServices.

Through the analysis and assessment process, including multiple data requests, consensus on the rationale for adjustments and the final dollar levels was reached between the Division and the Company in all categories, excluding vegetation management. Among the items utilized by the Company, the Division, and PowerServices in reaching a consensus were the quarterly reports[5] comparing the historical ISR Plan proposed budgets to actual expenditures, together with the historical budgets and spending by category as reflected in Appendix-2. Additionally, there was substantial discussion concerning individual Asset Replacement programs, I&M costs, System Capacity load relief projects, and the continued need for a comprehensive Long Range Plan. Similar to FY 2014 and FY 2015 Plan reviews, Verizon's responsibility for a portion of vegetation management costs was discussed at length. The FY 2016 ISR Plan, as adjusted during the evaluation process, is reflected in the Company's December 23, 2014, 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 October 10, 2014, with PowerServices' recommended adjustments listed. PowerServices and the Company agreed on all adjustments except vegetation management. The following is a detailed discussion of the categories and adjustments.

[5] PowerServices referenced the Company's FY 2015 ISR second quarter update. On February 13, 2015, the Company filed the FY 2015 ISR third quarter update which was not incorporated in this report and does not change the outcome of the evaluation or recommendations.

II. CAPITAL INVESTMENT PLAN

A. Overview

I have evaluated the $73,300,000 FY 2016 Capital Spending Plan proposed by the Company, along with its supporting testimony and exhibits as contained in its filing dated December 23, 2014. I first reviewed the initial proposed ISR Plan submitted to the Division dated October 10, 2014 in the amount of $76,500,000. Over a period of approximately sixteen (16) 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 proposal in October 2014, our adjustments, and the Company's proposed final budget as shown in Chart 7 of the FY 2016 ISR Plan as filed on December 23, 2014 in Docket No. 4539. The $73.3 million is the consensus level reached through the evaluation process.

Proposed FY 2016 Capital Outlays by Key Driver Category

SPENDING RATIONALE	INITIAL FY2016 PROPOSED BUDGET (10-10-14)	POWERSERVICES ADJUSTMENTS	FILED FY2016 PROPOSED BUDGET (12-23-14)	
Customer Request/Public Requirements	$ 15,747,000	$ (100,000)	$ 15,647,000	
Damage/Failure Total	$ 11,177,000	$ -	$ 11,177,000	
Subtotal	*$ 26,924,000*	*$ (100,000)*	*$ 26,824,000*	*Note (1)*
Asset Condition	$ 27,153,000	$ (3,100,000)	$ 24,053,000	
Non-Infrastructure	$ 275,000	$ -	$ 277,000	
System Capacity and Performance	$ 22,148,000	$ -	$ 22,148,000	
Subtotal	*$ 49,576,000*	*$ (3,100,000)*	*$ 46,476,000*	
Grand Total	**$ 76,500,000**	**$ (3,200,000)**	**$ 73,300,000**	

Note (1): The Company's 12/23/14 FY 2016 Electric ISR Plan incorrectly indicates a Subtotal of $36,824,000 (see page 8 of 13)

The Company projects the need for $15,647,000 in Customer Request/Public Requirements spending and $11,177,000 in Damage/Failure spending. This is approximately thirty-seven percent (37%) of the ISR Plan Capital requirements and ten percent (10%) higher than the FY 2015 budget. The majority of projects in these categories are not precisely defined because specific customer requests have not been made and damage or failure is yet to occur. Historical spending levels tend to serve as the primary method to develop a budget. Additionally, economic conditions are a factor considered in adjusting historical costs. There are both upward and downward trends in new construction activity combined with the effects of inflation on the cost of raw materials, transportation, and labor. For these reasons, it is reasonable that the Customer Request/Public Requirements will trend upward over time and, absent identification of major projects, incremental annual increases are expected. It is anticipated that the Damage/Failure category will be influenced similarly, but would eventually taper once the system is fully inspected and major system projects and asset replacements under the I&M program are completed.

It should be noted that the Company exceeded the FY 2014 Plan non-discretionary budget by 19% and is positioned to exceed the FY 2015 ISR by over $10 million, or 42%. These are important data points that do not necessarily influence future budgets, but do represent a recent trend of increased spending in the non-discretionary category. The Company has proposed a FY 2016 ISR budget for non-discretionary spending that is consistent with *average* historical spending levels but is less than the forecasted FY 2015 budget. The Company agreed to lower the FY 2016 budget for Customer Request/Public Requirements from $15,747,000 to $15,647,000 based on an observation related to third party pole attachment cost responsibilities. I will discuss the third-party attachment adjustment, the FY

2015 ISR budget variance, and cost trends for non-discretionary spending in more detail in Sections B and C.

Since the budgets for the majority of 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 remaining three (3) major categories of spending rationale for the FY 2016 budget are Asset Condition, Non-Infrastructure, and System Capacity and Performance. These categories, which are discretionary in the sense they are based on engineering, safety, reliability and economic analyses, are budgeted at $46,476,000 for the remaining sixty-three percent (63%) of the proposed capital budget. Asset Condition and System Capacity and Performance categories comprise ninety-nine percent (99%) of the discretionary budget. System Capacity and Performance continues to be an area of focus since the engineering rationale and alternative solutions for individual load relief projects are not necessarily apparent in the context of holistic system needs.

Discretionary spending is becoming more important as the Company initiates major substation projects due to system capacity constraints and asset condition problems. Solutions are long term strategic investments that are part of a comprehensive capital plan. In the FY 2015 ISR proceedings, I recommended, and the Company agreed to initiate, a System Capacity Load Study and develop a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. This Long Range Plan is critical to the overall capital investment strategy for building and maintaining a robust and reliable electric system. It provides the long term strategy addressing the sequence, timing and budgeting of asset replacements and major substation capacity projects. I also recommended, and the Company agreed, to provide a detailed budget for System Capacity & Performance and Asset Condition projects, and an evaluation of proposed projects as compared to the Long Range Plan. The materials and information provided by the Company were used to evaluate discretionary spending.

For the three categories (Asset Condition, Non-Infrastructure, and System Capacity and Performance), the initial proposed budget was $49,576,000, which has been adjusted down to $46,476,000 in the final FY 2016 ISR Plan Proposal filing, based on the consensus between the Division, PowerServices, and the Company. In Sections D, E, and F I will discuss each of these categories separately, explaining the $3,100,000 overall reduction. I will also compare the FY 2016 ISR proposal to historical budgets and actual expenditures to provide 5-year trending analysis for both non-discretionary and discretionary categories.

B. <u>Customer Request/Public Requirements Category</u>

The initial proposed FY 2016 ISR Plan included $15,747,000 of Customer Request/Public Requirements cost. This compares to a FY 2015 ISR budget and forecast of $14,537,000 and $18,493,000 respectively.

SPENDING RATIONALE	Initial FY2016 (10-10-14)	PowerServices Adjustments	Final FY2016 (12-23-14)
Customer Request/Public Requirements	$ 15,747,000	$ (100,000)	$ 15,647,000

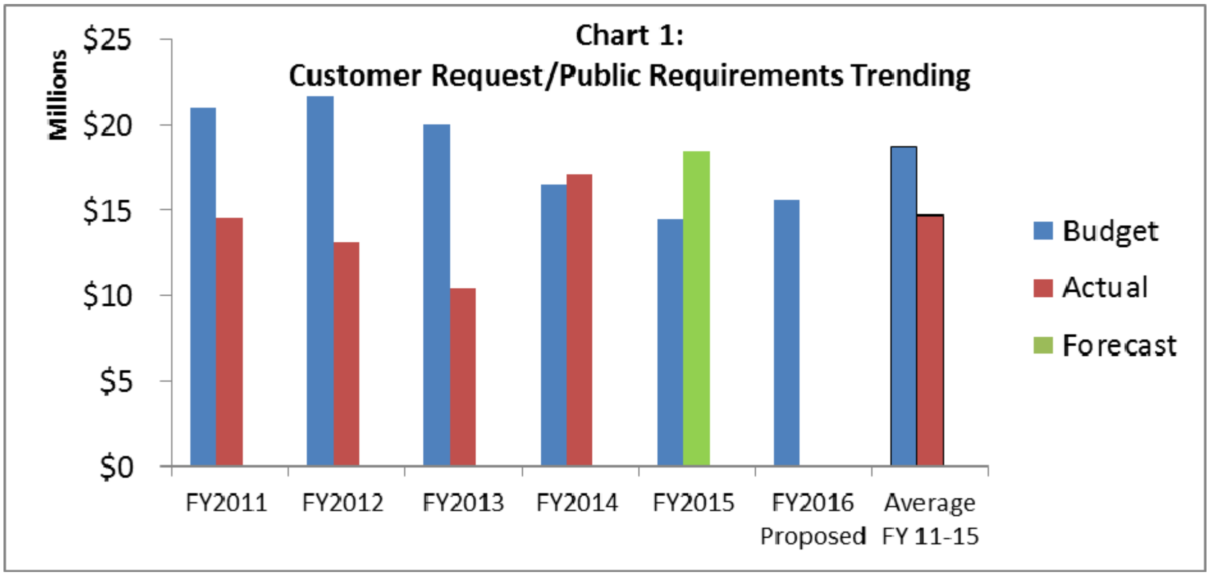
SPENDING RATIONALE	Filed FY2015	Expected FY 2015 Over/(Under) Budget (from Q2 Filing)	FY2015 Forecast (from Q2 filing)
Customer Request/Public Requirements	$ 14,537,000	$ 3,956,000	$ 18,493,000

Thus, the Company expects to exceed the Customer Requirements/Public Request budget by $4 million in FY 2015. Review of this variance is important in establishing trends or impacts to the FY 2016 forecast. According the Company's filing[6] the major drivers as of the second quarter, are:

- $1.2 million for reclassification between transmission and distribution projects associated with Shun Pike,
- $900,000 for additional costs incurred on the I-195 relocation project due to undocumented third-party existing utilities, which resulted in additional contaminated soil displacement in combination with additional labor hours to meet schedule changes,
- $900,000 for Watch Hill underground work occurring in FY 2015,
- $500,000 for Ocean State New Business Residential blanket due to higher demand and costs to date, and
- $500,000 for Nasonville 127W41; an emergent project to meet customer demand.

[6] Docket 4473 – National Grid's Electric Infrastructure, Safety, and Reliability Plan Quarterly Update – Second Quarter Ending September 30, 2014

In reviewing the variance explanations both independently and collectively, PowerServices does not believe that the events are reoccurring or necessitate a specific adjustment to the FY 2016 budget. As shown in Chart 1 below, the Company has, on average, historically underspent in this category.



However, closer evaluation of the past two years indicates that the Company is beginning a trend of exceeding budgeted amounts. A statement from the Company's FY 2015 ISR filing summarizes the budgeting dilemma.

> "…investments associated with these categories of work are non-discretionary, both in terms of timing and scope and are driven by forces outside the control of the Company, these categories of spending are subject to necessary and unavoidable deviations."[7]

PowerServices agrees that projects controlled by external entities are difficult to budget and schedule, but the magnitude of the FY 2015 variance causes concern. I am not satisfied that

[7] National Grid's Proposed FY 2016 Electric Infrastructure, Safety, and Reliability Plan filing dated 12-23-15; p. 9

the deviations are "necessary and unavoidable". A closer examination of projects exceeding budget limits is warranted and to the extent that the Company did not reasonably incur expenses, recovery may be impacted.

A minor adjustment to the Customer Request/Public Requirements category resulted from a detailed analysis of the budget categories, specifically Third Party Attachments which refers to communications companies or other parties that install facilities on Company or jointly owned poles under mutual agreement. PowerServices observed that the Company was likely absorbing costs to accommodate non-conforming attachments that would normally be borne by the attaching entity. It was recommended, and the Company agreed, to seek reimbursement from third-party attachers for non-conforming attachments, and that the FY 2016 ISR budget be reduced. Consensus was reached and the Customer Request/Public Requirements category was adjusted by $100,000 to $15,647,000.

C. <u>Damage Failure Category</u>

The initial proposed FY 2016 ISR Plan included $11,177,000 in the Damage/Failure category for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. This compares to a FY 2015 ISR budget and forecast of $9,816,000 and $16,109,000 respectively.

SPENDING RATIONALE	Initial FY2016 (10-10-14)	PowerServices Adjustments	Final FY2016 (12-23-14)
Damage/Failure Total	$ 11,177,000	$ -	$ 11,177,000

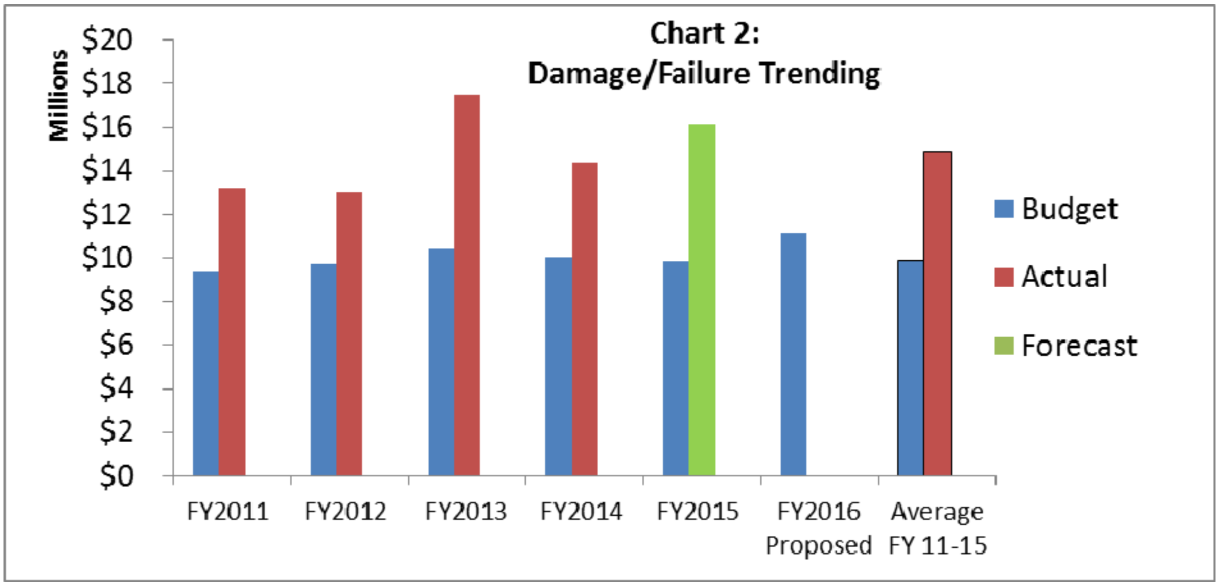
SPENDING RATIONALE	Filed FY2015	Expected FY 2015 Over/(Under) Budget (from Q2 Filing)	FY2015 Forecast (from Q2 filing)
Damage/Failure Total	$ 9,816,000	$ 6,293,000	$ 16,109,000

Similar to the Customer Requirements/Public category, the Company anticipates a significant variance in FY 2015 totaling $6.3 million which is 64% over-budget. According the Company's filing[8], as of the second quarter, the Company is $3.1 million over budget due to:

- $2,500,000 due to the Ocean State damage/failure blanket with recent increased trend in the identification and replacement of assets by Operations in this blanket, and
- $800,000 for Sockanosset #2 transformer to account for the costs of the spare transformer unit that was installed.

The forecasted fiscal year variance attributable to blanket projects is $6.3 million, suggesting that the Company expects to spend over $3 million in blanket projects for the remainder of FY 2015. The FY 2016 Plan indicates the continuance of the Ocean State blanket project with an $8.5 million budget for almost 75% of the total Damage/Failure budget. The blanket project covers capital spending to address issues that have been identified for immediate repair as part of the I&M program. The reasonableness of the FY 2016 budget is somewhat subjective, as equipment damage is unforeseen and levels of failure are generally based on historical trends. A review of historical Damage/Failure budgets versus actual spending (Chart 2) indicates that the Company's FY 2016 proposed budget is consistent with previous years and slightly below the historical average.

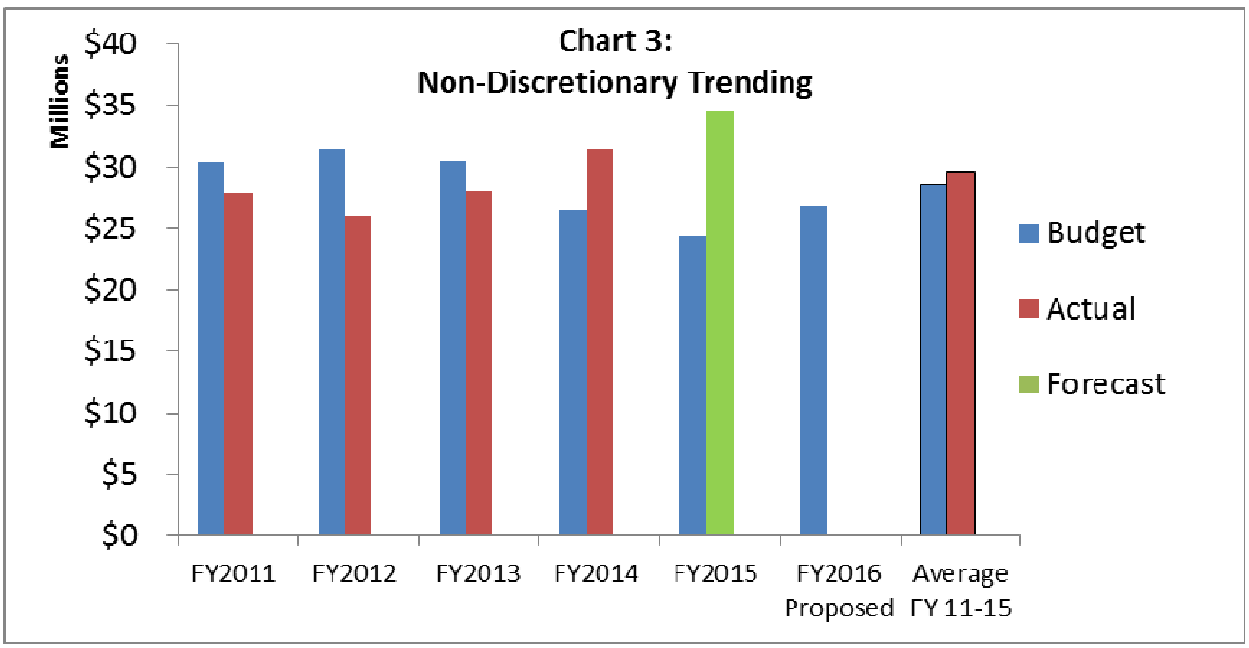
[8] Docket 4473 – National Grid's Electric Infrastructure, Safety, and Reliability Plan Quarterly Update – Second Quarter Ending September 30, 2014



Nonetheless, Chart 2 clearly shows that the Company is consistently overspending in this category. The solution is not necessarily a budget increase. The magnitude and frequency of variances reveals several areas of concern, including whether the Company is a) accurately reflecting costs; b) monitoring the type and level of work performed under the I&M program which influences the Damage/Failure expenses; and/or c) using appropriate methodologies to estimate the budget. Discussions with the Company paired with filing information suggest that further scrutiny of charges against this spending category is planned, and that FY 2015 adjustments may occur due to re-allocation of storm work and/or blanket projects. Additionally, although the Company does not control the failure rate of equipment, it can control the scheduled inspection and replacement of assets under the I&M program. The Company has agreed to assess program cycles and spread work over longer periods of time. The anticipated result will be lower annual Damage/Failure costs while maintaining expected levels of system reliability. This is discussed in more detail in the I&M Section D.

Upon conclusion of the evaluation, there is no adjustment to the Company's proposed budget of $11,177,000 in the Damage/Failure category, but rather focused attention on project charges, proper cost allocation, and I&M program cycle adjustments is recommended. Improvements in these areas should yield a lower variance in FY 2016 and serve as a best practice for ongoing ISR plans.

This brings the total non-discretionary categories of Customer Request/Public Requirements and Damage/Failure to $26,824,000, which is 37% of the total Capital Investment Budget by Key Driver Category. A comparison of historical spending versus budget is shown in Chart 3.



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

The Asset Condition category represents a combination of strategies and programs targeting equipment replacement to maintain reliability performance. This spending rationale is further divided into Asset Replacement and Inspection & Maintenance (I&M) components. The I&M Program is a result of successful transition of previous Feeder Hardening, Feeder Health, and associated Operation & Maintenance activities. The Asset Replacement and I&M programs are budgeted at $18,948,000 and $7,605,000 respectively. An additional budget of $600,000 is earmarked for Safety, bringing the total Asset Condition budget to $27,153,000. This compares to the FY 2015 budget and forecasted actuals of $19,511,000 and $22,191,000 respectively.

SPENDING RATIONALE	Initial FY2016 (10-10-14)	PowerServices Adjustments	Final FY2016 (12-23-14)
Asset Condition	$ 27,153,000	$ (3,100,000)	$ 24,053,000

SPENDING RATIONALE	Filed FY2015	Expected FY 2015 Over/(Under) Budget (from Q2 Filing)	FY2015 Forecast (from Q2 filing)
Asset Condition	$ 19,511,000	$ 2,680,000	$ 22,191,000

After detailed review including data requests, meetings, and conference calls, the Company and Division reached the consensus that this category should be adjusted downward by $3,100,000 to $24,053,000, or an eleven (11%) reduction.

1. <u>Asset Replacement</u>

The Asset Replacement category contains multiple year project specific work along with recurring programs that have been included and reviewed in prior ISR Plan filings. Proposed budgets in this discretionary category are generally based on equipment condition, criticality rankings, and the Company's planned level of work. Four of the recurring programs comprise forty-two (42%), or $8 million, of the total Asset Replacement budget. Of these, the URD cable strategy, underground cable replacement, and metalclad switchgear replacement programs are generally trending under-budget over the past two years. PowerServices proposed reductions in each category and the Company agreed to meet lower budgets by re-prioritizing and deferring select projects, resulting in a $2.2 million adjustment. This is an example of leveraging the inherent flexibility of discretionary spending, which allows the Company to adjust work schedules to control annual budgets while maintaining system reliability.

The components of the fourth category, substation transformer replacement, were evaluated in detail to determine if scheduled replacements of both Lafayette #30 and West Cranston #21 transformers were appropriately supported by asset condition issues. Since these are major projects, they were also reviewed for alignment with the Company's System Capacity Study and Long Range Plan, as addressed by the following in my FY 2015 ISR Plan report:

> "…I have had extensive conversations with the Company regarding the need to harmonize asset replacement with a comprehensive, long range system strategy. The Company has successfully transitioned from a series of isolated and often reactive maintenance activities to segmented programs or strategies. The next step is to make certain that activities amongst the programs support a unified system capacity strategy. For instance, programs such as substation transformer, breaker or recloser replacement include equipment that may be replaced due to asset condition or may be a part of work driven by capacity (load relief) requirements. In either case, the type of equipment installed along with the timing and sequence of replacement should align with an overall System Capacity Plan ("Long Range

Plan"). *Going forward, asset replacements scheduled within the Asset Condition category should be evaluated against the results of a System Capacity Study and resulting Long Range Plan before inclusion in the ISR Plan (emphasis added)*".

For the evaluation, PowerServices requested information on transformer age, size, loadings, assessment criteria, test results, criticality ranking, system capacity studies, and any other information used in the decision for replacement. In response, the Company shared that test results for the 56 year old transformer at Lafayette revealed moisture and deteriorated insulation, both conditions detrimental to performance and an indication that the unit has a high likelihood of failure. The transformer is also overloaded. The Company had not performed a system capacity study or Long Range Plan for the area. Given the significant issues with asset condition, I agreed that this project should proceed without the recommended studies. My analysis is limited to the proposed scope and support of any variation or project expansion will be predicated on the Company providing an adequate study to support the work.

Similar discussions on West Cranston #21 transpired. The 44 year old transformer is deteriorating and requires systematic maintenance. Although test results do not indicate imminent catastrophic failure, replacement with a larger unit is scheduled to satisfy condition concerns, meet projected load growth in the region and improve load transfer capability. The Company's system study in the area is expected to be complete in the third quarter of 2016. After full review, it was determined that the Company could rely on a spare transformer while pursuing a lower cost repair strategy to extend the life of the current transformer. This alternative mitigates a significant down payment on a new transformer until an area study confirms the need, and reduces the FY 2015 ISR Asset Replacement budget by $530,000.

Within the Asset Replacement category are two capital intensive substation replacement projects commencing in the FY 2015/FY 2016 period. First, the South Street substation project is sanctioned at $18 million over four years with a FY 2016 budget of $4.6 million. Second, the Southeast substation project is projected at $14 million over four years with $50,000 budgeted in FY 2016. As discussed within this and prior reports, the Company is embarking in a period of increased capital investment to replace aged and constrained major assets across the system. Expenditures for major asset replacement projects, in tandem with current projects in the System Capacity & Performance category (discussed in Section F), are projected to exceed $100 million over the next five years. The magnitude of expenditures calls for additional scrutiny of engineering rationale and project sequence to ensure that cost effective alternatives are considered, the level of planned work is viable over the fiscal year, and that frequent and inordinately steep ratepayer impacts are avoided.

South Street is a major substation serving downtown Providence and the surrounding area. The planned work for the station is a recommendation from the Providence Area Long Term Supply and Distribution Study ("Providence Long Term Study") completed in May, 2014. The study identified several issues in this densely populated and highly loaded area, mainly associated with the condition of indoor stations, underground cables and substation transformers. Most indoor stations were constructed between 1924 and 1951. The study outlines preferred plans for the region totaling nearly $200 million of which the South Street plan is a subset. The Providence Long Term Study does not establish the sequencing of infrastructure development, but South Street is one of the more critically ranked indoor stations within the plan and has been prioritized by the Company for inclusion in the FY 2016 ISR Plan. The recommended work includes building a new multi-level indoor station, relocation/retirement of equipment, existing building demolition, and other new construction. At this time, the Company estimates investments of $85.5 million over four years to implement comprehensive solutions.

PowerServices and the Division previously attended a South Street substation tour sponsored by the Company which allowed firsthand inspection of equipment. Further review of station pictures and detailed discussions of the study confirm that asset condition is a primary driver. There are also local development needs necessitating equipment relocation. The Company stated that some costs are attributable to the developer and that the project completion date in 2019 is aggressive but must align with the developer’s needs. A subsequent Providence area short term study focusing on the Providence network extending beyond the substation is in progress and expected to be complete in 2015. The long and short term studies interact closely since the underlying assets are inter-tied and, ideally, both studies should be complete before developing the overall asset replacement strategy. PowerServices is satisfied that the South Street project should commence and proposes no adjustments to the FY 2016 ISR budget of $4.6 million. However, the Company should revisit the scope and budget once the Providence short term study is complete, indicating findings and refinements in the FY 2017 ISR pre-plan information.

Lastly, PowerServices is concerned that due to the uncertainties and complexity of the South Street project, scope changes are inevitable, there is exposure to significant budget increases, and the timeline is too aggressive. The Company is undertaking a major project in its most densely populated area and great care must be taken for diligent planning and methodical execution. A project of this magnitude with major expenditures commencing within 24 months should be better defined and budgeted. Overall, the Company's plans lack detailed design, identification of risks and mitigation strategies, and adequate accuracy in cost estimates. The project should include this level of detail before the FY 2017 ISR to avoid unexpected and potentially massive budget overruns. This is but one example of a broader need to implement significantly better budget identification, controls and enforcement.

The Southeast Substation project is a combination of work planned at Pawtucket No. 1 station and the Southeast site. Currently, Pawtucket No. 1 serves area load, including the City of Pawtucket underground network. The station has numerous safety, asset condition, operational and maintenance issues. The Company evaluated alternatives and derived a preferred plan which includes decommissioning, building demolition, and construction at Pawtucket No. 1 to serve a portion of the current load, along with construction of a new outdoor substation at Southeast to serve the remaining load.

Pawtucket No. 1 is part of the Blackstone Valley South capacity study area which is slated to be evaluated at a later date as part of the Long Range Plan development. Therefore, the Company provided a traditional Area Study, completed in December 2014, to support the recommended plan. PowerServices agreed to evaluate the project against an Area Study in lieu of a formal System Capacity Study since it was identified during a transitional phase of planning. Based on the asset condition and capacity information made available, I agreed that the project should commence and that the limited FY 2016 ISR budget of $200,000 is appropriate to cover preliminary engineering. Further review in FY 2017 is warranted since the study was limited to the area served by Pawtucket No. 1 as opposed to a broader area including adjacent regions. Most importantly, as emphasized with every major project, the Company must be diligent in creating a clear project path to avoid the scope and budget creep customarily seen when projects pass through various sanctioning phases.

The remaining budget items in the Asset Replacement category were reviewed with no additional adjustments. This brings the total Asset Replacement adjustments to $2,200,000 for a FY 2016 ISR Plan proposed budget of $16,748,000.

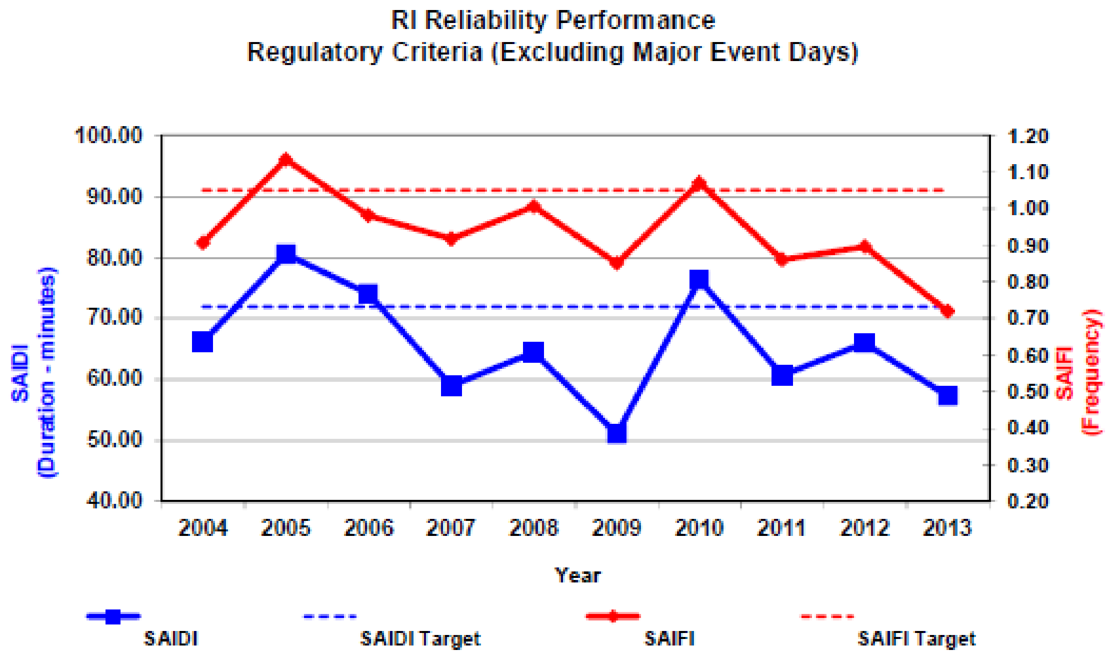
2. <u>Inspection & Maintenance Program.</u>

   The I&M Program addresses deteriorated assets to ensure that the distribution and sub-transmission system is safe, reliable, and environmentally sound. Inspections are performed on a five-year cycle and the proposed plan is designed to fund repair work necessary to reach a ten-year repair cycle. The Company has inspected 83% percent of its overhead distribution system feeders, and estimates by the end of FY 2015, distribution overhead I&M repairs will reach approximately 20% of all feeders. The Company categorizes deficiencies found during inspections as Level I, II and III. Costs for Level I repairs, requiring immediate attention, are captured under the Damage/Failure category. The I&M Program also includes mobile elevated voltage testing. This program utilizes a new technology that was recently impacted by a patent infringement case, resulting in delays. In response, the Company has adopted a substitute technology with the same service provider that was awarded the original contract. PowerServices supports the alternative approach. The total proposed FY 2016 I&M budget is $7,605,000, or eight percent (8%) above the FY 2015 budget of $7,040,000.

PowerServices observes that continued spending is critical and that successful program implementation has influenced excellent reliability results. The Company is meeting annual service reliability targets and statistics show an improving overall trend. (Chart 4).[9]

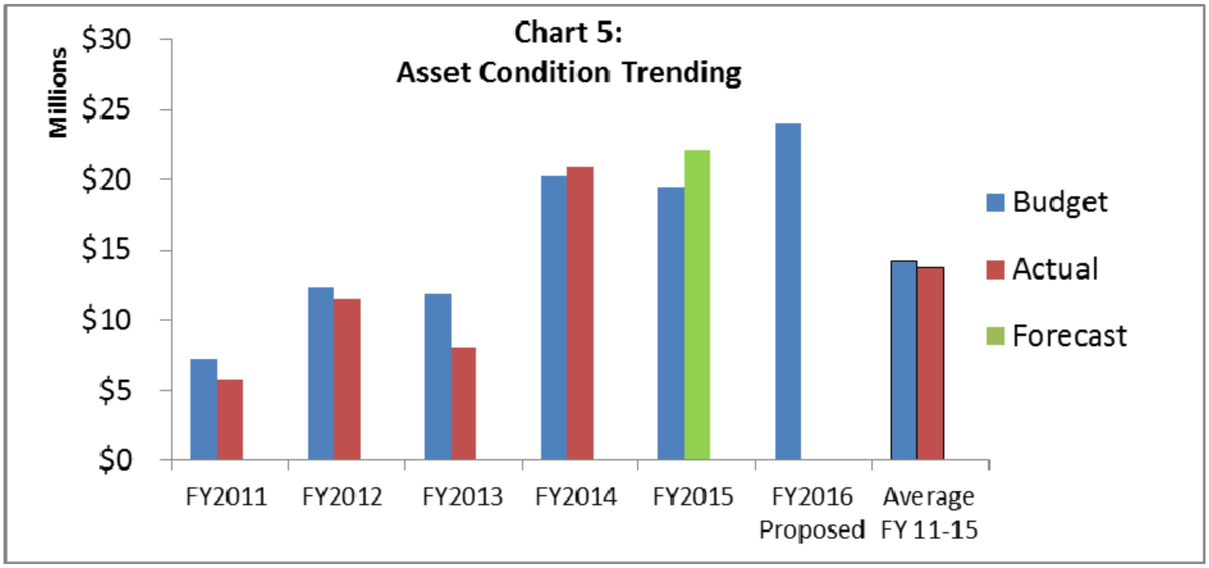
[9] National Grid's Proposed FY 2016 Electric Infrastructure, Safety, and Reliability Plan filing dated 12-23-15; p. 23

Chart 4



However, it is important to explore opportunities to achieve satisfactory reliability at less cost. Discussions were held with the Company to assess the benefits or risks of reducing the annual I&M Program budget. The Company has discretion over equipment repair plans and the latitude to re-prioritize schedules if there are limited customer impacts and no imminent safety or reliability concerns. The Company ultimately agreed to an I&M program budget reduction of $900,000 and to continued assessment of inspection and repair cycles to meet budget targets. Immediate repairs of Level I deficiencies would continue, and absent a significant number of critical issues, repairs should decrease as fewer feeders are inspected over a fiscal year. Subsequently, Damage/Failure expenses are anticipated to decrease and the Company may be better positioned to manage that non-discretionary budget.

In summary, concurrence was reached on budget reductions of $2,200,000 for Asset Replacement and $900,000 for the I&M program for a total of $3,100,000. This brings the total FY 2016 ISR proposed budget for Asset Condition to $24,053,000, comprised of $16,748,000 for Asset Replacement, $6,705,000 for the I&M program, and $600,000 for Safety. The proposed budget is consistent with annual trends (Chart 5).



E. Non-Infrastructure Category

This category is for telecommunications and other capital expenditures needed for operation, which are neither related to condition nor system capacity. I consider this $275,000 of capital expenditures prudent and necessary, while consistent with prior costs.

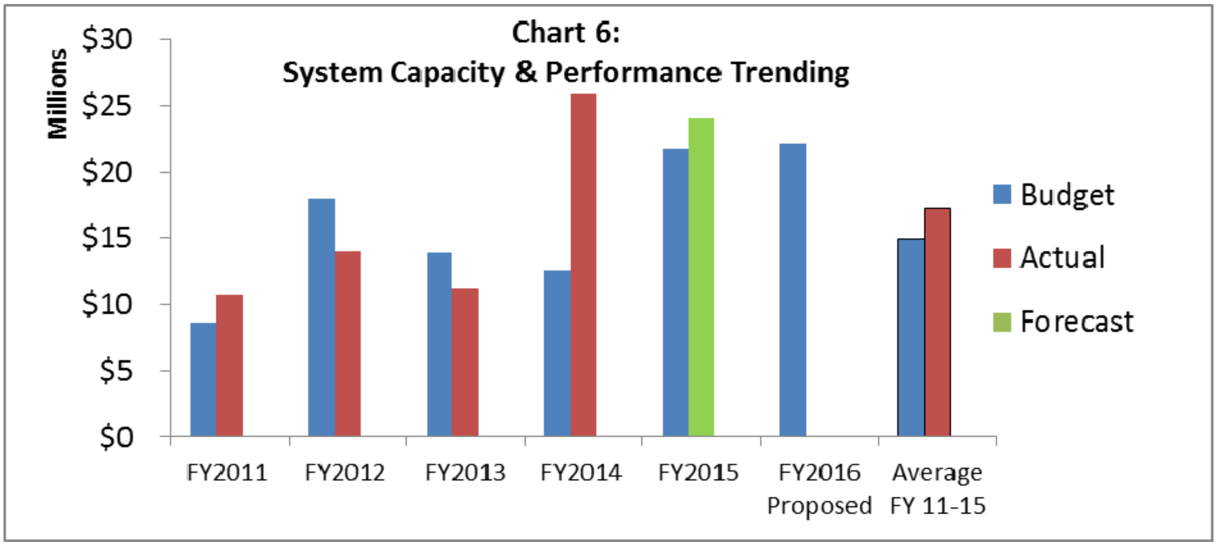
F. System Capacity and Performance Category

The System Capacity and Performance Category is comprised of both Load Relief and Reliability Projects. A significant portion of this discretionary budget is dedicated to substation capacity expansion projects. The Company proposed to expend $22,148,000 in the System Capacity and Performance Category, or thirty percent (30%) of the total FY 2016 ISR Plan budget. Of this, $18,074,000 or eighty-two percent (82%) is designated for capacity related projects. The overall budget is slightly higher than the FY 2015 budget of $21,759,000 and is lower than the Company's FY 2015 actual forecast of $24,084,000.

SPENDING RATIONALE	Initial FY2016 (10-10-14)	PowerServices Adjustments	Final FY2016 (12-23-14)
System Capacity and Performance	$ 22,148,000	$ -	$ 22,148,000

SPENDING RATIONALE	Filed FY2015	Expected FY 2015 Over/(Under) Budget (from Q2 Filing)	FY2015 Forecast (from Q2 filing)
System Capacity and Performance	$ 21,759,000	$ 2,325,000	$ 24,084,000

Variance explanations for the Company's FY 2015 forecast are similar to those historically encountered, consisting of schedule shifts and increased costs as project scopes and engineering are refined. These schedule adjustments, influenced by factors such as material and workforce availability or permitting requirements, are expected in the normal course of major project work. Review of prior actual expenses as compared to budget (Chart 6) shows that the company, on average, is tracking very close to budget, although individual years may have broad variances. After thorough evaluation of supplemental materials provided by the Company, as discussed below, the proposed budget was not revised and remains at $22,148,000 for the System Capacity and Performance Category.



The Company's FY 2016 ISR Plan prioritizes eleven (11) major Load Relief projects for $18 million dollars or eighty (80%) of the total System Capacity and Performance budget. Seven (7) of the projects were included in the FY 2015 ISR Plan with four additional projects added to the current Plan (Chart 7).

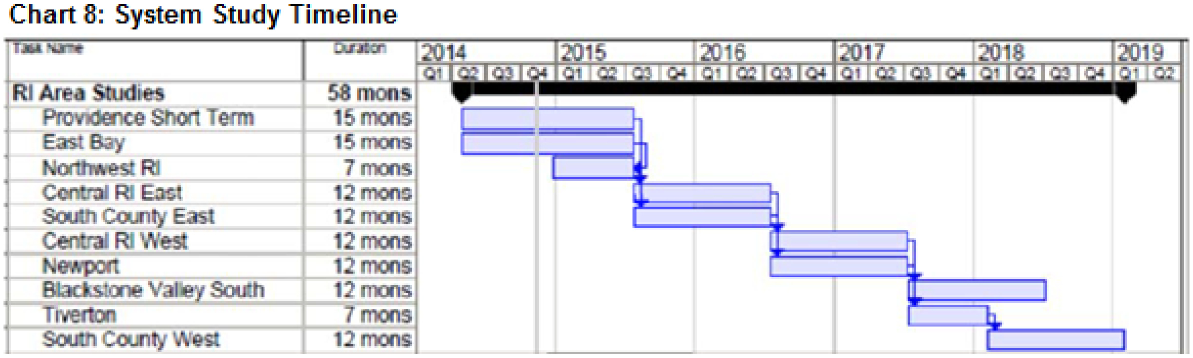
Chart 7 Load Relief Projects

Projects	Status	FY 2016 Budget ($000)
Kilvert St - DSub	Existing	1,100
Chase Hill (Hopkinton) & Related	Existing	4,900
New London Ave (West Warwick) & Related	Existing	6,800
Newport & Related	Existing	1,800
Clarke St	Existing	250
Highland Drive	Existing	1,200
Kent County	Existing	1,210
Quonset Substation	*New*	480
Providence LT Study	Future	0
East Bay Study	*New*	84
Jepson Substation (Newport Area)	*New*	250
	Total	18,074

These are typically multi-year projects with significant budget requirements for design/engineering, permitting, and construction. Historically, the Company identified projects as part of an annual capacity planning process using a combination of metrics including historical load data, future load projections, and system flexibility in response to contingencies. Beginning with the FY 2016 Plan, I requested that the addition of major projects to the Substation Capacity and Load Relief, and Asset Replacement categories be supported by a Long Range Plan. In response, the Company provided the Providence Area Long Term Supply and Distribution Study and the Quonset Point Study. Upon evaluation of the system capacity expansion plan in conjunction with information that the Company provided during conference calls, I have the following observations and recommendations:

1. The Company is transitioning to system-wide capacity studies and has identified ten (10) study areas in Rhode Island that are electrically isolated loads where solutions are not offered from adjacent areas. Current estimates indicate that all system capacity studies will be complete by 2019 (Chart 8).

Chart 8: System Study Timeline



A comprehensive 10-year Long Range Plan cannot be developed until all studies are complete and, at best, would be made available in the FY 2020 ISR Plan filed in 2018. Although first steps have been taken, the Company's timeline to complete a full system study is longer than expected and the Company continues to schedule isolated projects that do not correlate to a system-wide plan. I recommend that the Company accelerate the schedule to develop a more robust long term capital investment strategy. All system capacity studies and the associated 10-year Long Range Plan should be accelerated and completed such that they are reflected in the FY 2018 ISR Plan.

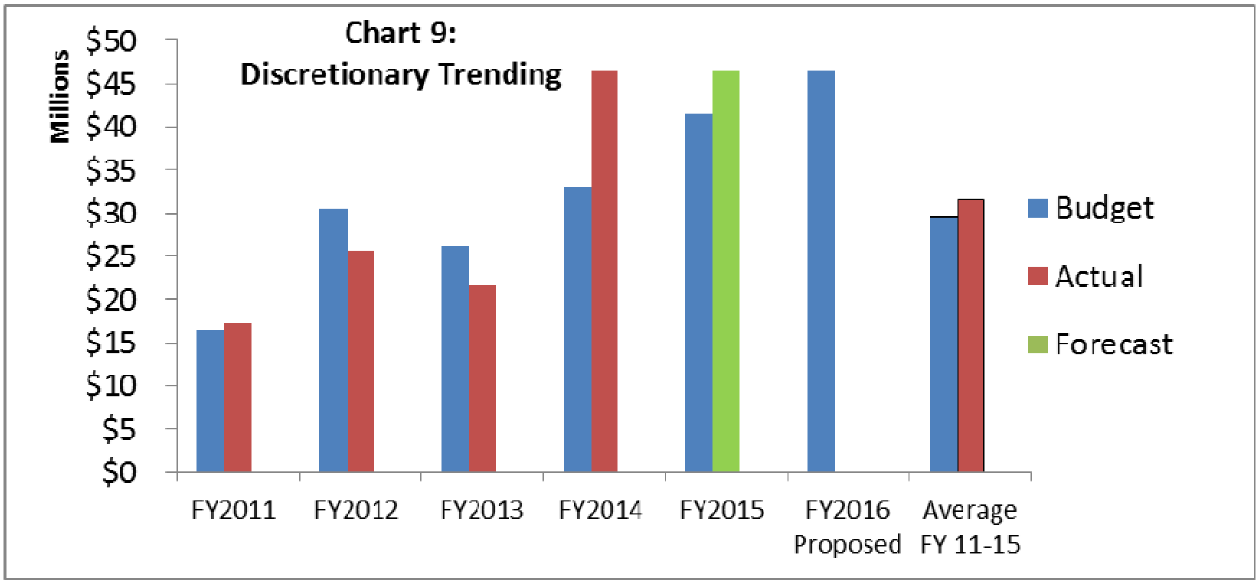
2. As discussed in my FY 2015 report, during this transitional phase as the Long Range Plan is developed the Company should continue work on existing Asset Replacement and System Capacity & Performance Projects as planned. New projects, unless compelled by imminent safety or reliability concerns, should be justified under the Long Range Plan before inclusion in the ISR Plan. In the FY 2016 ISR Load Relief category, the Company added new projects for East Bay Study and Jepson Substation. Both lack a system capacity study to support proposed work, and I recommend that expenses be limited to preliminary assessment and completion of the required studies. Further support of these projects is conditioned on results of a final Long Range Plan yet to be delivered by the Company.

3. The Company also added Quonset Point in the Load Relief category. As in the case of Southeast Substation in the Asset Replacement category, Quonset is supported only by the Company's traditional study that is limited to a specific area. The proposed work is

driven by industrial expansion expected to create a transformer capacity constraint. The solution will address the constraint along with area reliability and transformer condition concerns. After evaluation of the area study and discussions with the Company, PowerServices supported inclusion of the project without budget adjustments, but offered alternatives to consider that would lower the overall project cost. Continued support of the project is conditioned on the Company's evaluation of cost effective alternatives and demonstration that proposed solutions align with the industrial expansion timing and capacity needs.

In summary, based on my evaluation, I recommend that for FY 2016, the System Capacity & Performance proposed ISR Plan budget of $22,148,000 remain unchanged and that the Company accelerate the timeline to complete System Capacity Studies and Long Range Plan development. My support of additional projects to the FY 2016 ISR Load Relief category, other than Quonset Point, is conditioned on the results of a final comprehensive Long Range Plan. I recommend that the Company evaluate lower cost alternatives for Quonset Point and provide analysis for ongoing support as part of the FY 2017 ISR filing. Most importantly, all future Asset Replacement and System Capacity & Performance projects should be justified under a comprehensive, system-wide Long Range Plan before inclusion in the ISR Plan, and the evaluation should be provided as part of ISR Plan filings.

This brings the total discretionary categories of Asset Condition, Non-Infrastructure, and System Capacity & Performance to $46,476,000, which is 63% of the total Capital Investment Budget by Key Driver Category. A trending analysis of Discretionary spending indicates that the Company is, on average, slightly exceeding budget and that costs are rising dramatically in recent years due to major capital improvement projects (Chart 9). The Company should continue efforts to refine internal processes that mitigate project scope creep and reduce variances between initial and project grade budgets.



III. VEGETATION MANAGEMENT

The Company's initial FY 2016 ISR Plan proposed expenditures of $9,034,000 for the Vegetation Management Program, which includes the Enhanced Hazard Tree Mitigation (EHTM) program. This is seventeen percent (17%) above the FY 2015 budget of $7,726,000. The major spending component is Cycle Pruning, budgeted at $5,414,000, which is above forecasted expenses of $4,895,000 for FY 2015. The budget reflects increased cycle pruning bid prices received by the Company to perform work under the Plan. The Company also included $150,000 in the EHTM category for Emerald Ash Borer management activities, which the Company anticipates becoming a threat throughout Rhode Island. I recommended that the Company take steps to fully understand the strategy for controlling or protecting from the Emerald Ash Borer before selectively identifying and removing hazard trees. Upon full assessment, the program may be funded in the future ISR Plans as determined appropriate. The Company agreed to reduce the proposed EHTM budget by $150,000 resulting in the final proposed FY 2016 ISR Plan budget of $8,884,000 for Vegetation Management (Chart 10).

Chart 10: VEGETATION MANAGEMENT	Initial Proposed Budget (10-10-14)	PowerServices Adjustment	Final Proposed Budget (12-23-14)
Cycle Pruning	5,414,000		5,414,000
Hazard Tree	1,150,000	(150,000)	1,000,000
Sub-T	220,000		220,000
Police/Flagman Detail	750,000		750,000
All Other Activities	1,500,000		1,500,000
Program Total	**9,034,000**	**(150,000)**	**8,884,000**

Overall, I find that the Company has implemented a robust vegetation management program resulting in reliability indices that continue to meet or exceed the Commission's benchmarks. I have evaluated the Vegetation Management Program in detail and on multiple levels in prior ISR Plan assessments. The Company has responded to my inquiries, sufficiently supported activities within the program, and now produces a Cost Benefit Report. Given the maturity of the program and its contribution to meeting reliability metrics, my assessment of the FY 2016 ISR Plan will again focus on the Company's obligation to request and recover Verizon's reimbursement for both routine and storm related vegetation management expenses, which have been a component of the Joint Ownership Agreement ("JOA") since its execution in the 1980.

I initially made it clear in the FY 2013 ISR Plan proceedings under Docket 4307 that the Company was not adequately or forcefully enforcing its rights under the JOA. In my evaluation of the FY 2013 Annual Report and Reconciliation dated August 1, 2013, I detailed the Joint Ownership Agreement ("JOA") between the Company and Verizon that establishes a geographical area of control that should realize an equal "50/50" sharing mechanism for pole ownership. Under Intercompany Operating Procedures ("IOP"), the respective company in a geographical area is responsible for pole maintenance and the companies pay each other a flat reciprocal rate of $500 for pole replacements. (Appendix-4 contains excerpts from the National Grid and Verizon Joint Ownership Agreement dated October 1, 1980 and Amended September 25, 2001.) In addition, I provided the following key excerpts from IOP J, which addresses cost sharing of vegetation management work (IOP J, Tree Trimming, is attached in Appendix-4):

1. Preventive maintenance tree trimming shall be performed on a joint basis when both companies have a need. When it is agreed that both parties will benefit from such Joint Tree Trimming, the division of costs will be 75% Electric Company and 25% Telephone Company.

2. Topping of trees, if they present a hazard to both parties, shall be performed jointly at a 50/50 division of cost.

3. Heavy storm work, such as required for hurricanes, wet snow, tornadoes, and ice storms, will be handled immediately without prior review. Agreement should be reached by field representatives of the two companies as soon as practicable after each major storm to determine for which lines and to what extent each party will participate, notwithstanding participation by another party. The parties agree to 50/50 basis for heavy storm work.

4. Miscellaneous costs associated with trimming, such as police protection, tree warden's payment, obtaining permissions, and state highway inspector, will be shared by the joint owners on the same basis as the IOP provides for trimming costs.

The IOP J obligation for vegetation management cost sharing is indisputable, and accordingly, I requested the Company provide specific details on pole replacement and vegetation management expenses, and efforts to collect Verizon's contribution in each ISR Plan proceeding since FY 2013. The documentation provided by the Company in response to my inquiries in the last four (4) proceedings lacked any indication of adjustments in the capital and expense categories for dollars either collected from, or that are the responsibility of, Verizon. My resulting recommendation, beginning with the FY 2013 Annual Report and Reconciliation and repeated in each ISR Plan process since then, has been that:

> "…costs which should be collected from Verizon should not be the responsibility of the electric ratepayers. Furthermore, I have recommended the Company aggressively enforce its right under the JOA including the IOP J and its collection of vegetation management cost responsibility from Verizon".

After four years of underscoring the Company's contractual rights and obligation to recoup expenses on behalf of electric ratepayers, the Company has failed to make meaningful progress or receive any payment from Verizon. The Company has represented it cannot identify that Verizon has ever reimbursed the Company for vegetation management and that Verizon does not believe it receives any benefit from vegetation management. If trees, limbs, vines, and other vegetation were not kept clear from right-of-ways, communications service to customers would absolutely be interrupted by falling or severed lines. It is absurd that a communications company contends it has no financial responsibility for electric utility vegetation management costs when that very communications company is attached to the electric utility's poles and benefitting from reduced outages. My experience in other jurisdictions is that Verizon has not disputed that it has a responsibility for vegetation management cost.

Most recently, in response to the Company's efforts to recoup vegetation management expenses, the Company reports in its FY 2016 ISR Plan that Verizon unilaterally terminated the

IOP J effective June 30, 2014. This is an extremely disturbing development and reinforces my opinion that Verizon has a complete disregard for its contractual obligation, safety of utility systems and the public, and reliability of electric and communications service.

The Company has not disputed Verizon's ability to terminate the IOP J, has not negotiated a new agreement, and has not aggressively pursued prior years' expenses. The Company has had ample time and opportunity to take action, yet conversely, the Company simply continues to budget for the collection of 100 percent of its vegetation management costs to be recovered from the electric ratepayers with NO contribution from Verizon. I believe this is an unacceptable practice and must be remedied. The Company has not demonstrated that it will reverse this trend and has not implemented an effective strategy to enforce vegetation management cost sharing. In my estimation, the Company is failing to recoup over $2,000,000 from Verizon each year. These expenses are a burden to the Company's electric ratepayers and are a benefit and windfall to Verizon. The 10 year net present value of a reoccurring adjustment in cost recovery for vegetation management based on adequate and appropriate collection of cost sharing from Verizon is over $15,000,000.

The Company has been stating that it is committed to continued negotiations and discussions with Verizon on the responsibilities of both parties for the payment of both routine and storm trimming costs, as well as other issues relative to the joint ownership of poles. During the FY 2016 ISR Plan evaluation and negotiation period between the Division and the Company, the Company agreed to provide a detailed action item list and timeline with benchmarks for aggressively dealing with the failure of collections for vegetation management costs from

Verizon. This was to include a much broader approach of also remedying other deficiencies in the JOA and the operating relationship between the Company and Verizon. The Division agreed, as part of its negotiation with the Company based on the Company's delivery of a detailed plan, to defer recommending a vegetation management adjustment in the FY 2016 ISR Plan. The initial plan delivered by the Company was neither detailed nor aggressive. After multiple discussions, the Company and Division ultimately agreed to a plan expected to guide the Company in negotiations and actions with Verizon.

The urgency to recoup vegetation management expenses under the IOP has extended to the point that I recommend a much more aggressive approach by the Company and the Division. I believe there are two fundamental avenues; litigation or regulatory action.

Regarding regulatory action, the Rhode Island Public Utilities Commission ("PUC") has historically had jurisdiction over both electric and telecommunications companies. Much of the telecommunications oversight has shifted to the Federal Communications Commission ("FCC") that regulates interstate and international communications. Similarly, oversight of many electric activities, including interstate transmission, is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). The oversight of both the FCC and FERC are in addition to any local or state authority that has oversight of electric and communications related activities.

In the case of Rhode Island, it is my opinion that enforcement of agreements between National Grid and Verizon that manage joint ownership and related services for infrastructure located within the state remain under the purview of the Division and the PUC. The PUC/DPUC is in a position to consider complaints and take action if either party fails to meet provisions in joint ownership agreements, including cost reimbursement. A recent example of state Commission jurisdiction over joint use agreements occurred in Massachusetts. As part of the proceedings related to cost recovery for a major winter storm, I provided testimony to the Department of Public Utilities ("DPU") recommending that the National Grid storm recovery be adjusted downward to reflect the recovery of vegetation management cost from Verizon as contained in the Joint Ownership Agreement ("JOA"), which I will point out is virtually identical to the agreement in force in Rhode Island between National Grid and Verizon. The Massachusetts DPU, in their Docket No. DPU 11-56 Order, made a significant adjustment in the vegetation management cost recovery to reflect what National Grid should be collecting from Verizon (see excerpts in Appendix-5).

In summary, I find the $7,726,000 FY 2016 level and a four year clearing cycle based on the Company's enhanced Vegetation Management Program to be appropriate, considering the anticipated level of benefits. I do not, however, believe that 100% of these costs should continue to be recovered from the electric ratepayers as part of the reconciliation process. Verizon has blatantly disregarded its requirements for vegetation management cost responsibility, and the subsidy by electric ratepayers to the profits of Verizon in an amount of approximately $2,000,000 a year must cease. Furthermore, the unrecovered portions of the vegetation management costs from prior years should be considered in corrective actions taken by the Company and the Division. The electric ratepayers certainly deserve the improved reliability and public safety that comes with the National Grid Vegetation Management Program, however, those same ratepayers should not be expected to pay for $2,000,000 a year or more of the program cost that is the contractual obligation of Verizon and from which the Verizon customers and most likely stockholders benefit.

I find the Company failed to demonstrate any meaningful progress in its negotiations and had not provided the Division with a cohesive plan intended to create substantive results. After multiple discussions, the Division and the Company ultimately reached an agreement on actions and timelines for aggressively pursuing payment from Verizon for both past vegetation management costs, and costs going forward. Furthermore, the Division and the Company have agreed on a process expected to remedy the inherent problems associated with an antiquated JOA.

Pending the Company taking an active approach which demonstrates that it has comprehensively pursued in a prudent and exhaustive manner all available measures to recover the vegetation management costs from Verizon, the Division reserves its right in the rate adjustment reconciliation of ISR Plan expenditures to request the withholding of rate relief equivalent to the past two years of vegetation management costs due and believed recoverable from Verizon under the JOA. This amounts to approximately $4,000,000. The Division will exercise this right in future ISR proceedings until the Company either recovers costs from Verizon or has exhausted all available measures to the satisfaction of the Division.

IV. SUMMARY AND RECOMMENDATIONS

The collaborative process between the Company and the Division resulted in a FY 2016 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 October 10, 2014 and the resulting December 23, 2014 filing of the FY 2016 ISR Plan Proposal. The consensus ISR Plan is a four percent (4%) reduction of $3,200,000 in the discretionary capital spending budget from the October 10, 2014 proposed level with an overall capital spending reduction of four (4%), or $3,350,000. The Customer Request/Public Requirements portions of the FY 2016 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. Conversations between PowerServices, the Division, and the Company failed to result in a downward adjustment that reflects Verizon's responsibility for Vegetation Management expenses. This issue of ratepayer subsidy has been evaluated in detail over the span of several years with no resolution. Rather than support the Company's unsuccessful approach in negotiations with Verizon, this ISR review has encouraged the Company and Division to develop an agreement comprised of more aggressive measures to pursue in order to address vegetation management and other global concerns regarding jointly owned assets.

As discussed in my previous reports, there continue to be numerous challenges in the next five to ten years. 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. Capital investment for major Asset Replacement and substation capacity projects is growing, and it is critical to carefully evaluate the risk mitigation benefits and alternatives such that the most cost effective solutions can be implemented. Most importantly, the Company should accelerate completion of a comprehensive Long Range Plan to ensure a methodical sequence of major work that addresses local capacity issues, while complementing a broader system enhancement strategy. The Company must prioritize these efforts and use the results of the Long Range Plan to support additional major Asset Replacement or Load Relief projects.

I support the FY 2016 Capital Budget as proposed at $73,300,000 with a value for the capital placed into service in FY 2016, plus cost of removal at $939,000. I also support the FY 2016 proposed VM Program at $8,884,000. Lastly, I support the I&M Program Operations and Maintenance Expenses at $3,333,000 which includes a System Capacity Study. Furthermore, I am a proponent for an annual adjustment process for the categories of Customer Request/Public Requirements and Damage/Failure.

<u>Capital Investment Recommendations</u>

1. National Grid shall accelerate development of a System Capacity Load Study and develop a 10-year Long Range Plan as part of the FY 2018 ISR Plan in order to increase the level of support and transparency for the capital budget. This Long Range Plan is critical to the overall capital investment strategy for building and maintaining a robust and reliable electric system. The Company shall submit a report with updates on modeling activities in addition to the proposed Long Range Plan (completed portions) at least 120 days prior to filing its FY 2017 ISR Plan Proposal, but in any event no later than August 31, 2015. This should be continued with each subsequent ISR Plan process.

2. National Grid shall revisit the scope and budget of the South Street substation project in the Asset Replacement category once the Providence short term study and preliminary engineering are complete, indicating findings in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015. The Company shall provide detailed design, identification of risks and mitigation strategies, and a refined budget for further evaluation.

3. National Grid shall limit FY 2016 expenses to preliminary engineering for the Southeast Substation project in the Asset Replacement category, and provide a detailed project scope, timeline and budget for further evaluation in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

4. National Grid shall limit FY 2016 expenses to system capacity studies and preliminary engineering for the East Bay Study and Jepson Substation projects in the System Capacity and Performance category until a 10-year Long Range Plan is complete, at which time the projects should be evaluated against the results of such plan.

5. National Grid shall evaluate cost effective alternatives for the Quonset Point project in the System Capacity and Performance category, and demonstrate that proposed solutions align with the industrial expansion timing and capacity needs. The evaluation shall be provided in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

6. National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

7. National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long Range Plan in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

8. National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long

Range Plan, in advance of the FY 2017 ISR Plan Proposal filing, but in any event no later than August 31, 2015.

9. National Grid shall continue 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 FY2017 ISR Plan Proposal, but in any event no later than August 31, 2015.

10. National Grid shall continue to submit its Metal-Clad Switchgear replacement program cost-benefit analysis to the Division prior to submitting the Company's FY2017 ISR Plan Proposal, but in any event no later than August 31, 2015.

<u>Vegetation Management Recommendations</u>

Because the Company has failed to demonstrate any meaningful progress or a cohesive plan intended to create substantive results in negotiations with Verizon, the Division and the Company have reached an agreement on action items and timelines for proceeding aggressively to begin the recovery of vegetation management expenses from Verizon. I recommend that National Grid fully cooperate with the Division in pursing the provisions of this agreement. In addition, I recommend the Division initiate a proceeding pursuant to its rights under Chapter 39-4-10 and 39-4-11 based on Verizon's unjust and unreasonable actions, which constitute a violation of the National Electrical Safety Code. Verizon's practices and disregard for the NESC result in unsafe, dangerous, and improper utility operation and maintenance, creating conditions in which public safety is endangered.

This concludes my Report on the Electric Infrastructure, Safety and Reliability Plan FY 2016 Proposal as filed by National Grid on December 23, 2014.

APPENDIX 1

Rhode Island Electric ISR
FY16 Plan – Meeting with Division and Greg Booth
August 25, 2014
1:00 p.m. to 3:45 p.m.

AGENDA

Topic	Presenter	Handouts	Time
Vegetation Management – - Cost Benefit Report - FY16 Program	Ryan Moe	A) Veg Mgmt Cost Benefit B) Attachment 1 (EHTM Reliability) C) Attachment 2 (Cycle Pruning Reliability)	1:00 – 1:30
Electric Infrastructure - System CYME Model - Long Range Plan - Capacity and Asset Condition Budgets - Substation Capacity Plans - Metalclad Replacement Program	Ryan Constable/ Glen DiConza/ Eileen Duarte	D) Prefile planning information: Long Range Plan, Asset Condition, System Capacity and Performance (Part 1 and Part 3 only; Part 2 contains Critical Energy Infrastructure Information and will be provided separately) E) Summary FY16-20 Working Draft Plan (for Asset Condition and System Capacity and Performance Categories) F) Detail Categories FY16-20 Working Draft Plan (for Asset Condition and System Capacity and Performance Categories) G) Metal Clad Replacement	1:30 – 3:00
I&M Cost Benefit Report	Emilio Agustin	H) I&M Cost Benefit	3:00 – 3:30
Wrap Up & Next Steps	Jennifer Grimsley		3:30 – 3:45

APPENDIX 2

Historical Budgets versus Actual

` Spending Rationale	FY 2006 Budget	FY 2006 Actual	FY 2007 Budget	FY 2007 Actual	FY 2008 Budget	FY 2008 Actual
Statutory/Regulatory	20,302,000	22,885,193	17,902,500	21,012,048	24,630,000	23,887,492
Damage/Failure	3,250,000	8,264,656	4,550,000	7,442,272	5,660,000	7,642,277
Total Discretionary	***23,552,000***	***31,149,849***	***22,452,500***	***28,454,320***	***30,290,000***	***31,529,769***
Asset Condition	9,323,000	5,828,465	8,641,000	8,342,907	10,020,000	12,559,436
Non-Infrastructure	793,000	(2,196,297)	990,000	3,041,061	75,000	385,109
System Capacity & Performance	10,276,500	10,980,393	12,961,500	11,545,608	12,434,000	13,558,424
Total Non-Discretionary	20,392,500	14,612,561	22,592,500	22,929,576	22,529,000	26,502,969
Grand Total	**43,944,500**	**45,762,410**	**45,045,000**	**51,383,896**	**52,819,000**	**58,032,738**
Vegetation Management	-	-	-	-	-	6,630,000
Inspection & Maintenance Program	-	-	-	-	-	-

` Spending Rationale	FY 2009 Budget	FY 2009 Actual	FY 2010 Budget	FY 2010 Actual	FY 2011 Budget	FY 2011 Actual
Statutory/Regulatory	24,022,668	21,171,756	23,726,000	19,311,885	21,014,000	14,631,340
Damage/Failure	6,596,000	8,345,442	7,919,000	9,031,133	9,365,000	13,194,101
Total Discretionary	***30,618,668***	***29,517,198***	***31,645,000***	***28,343,018***	***30,379,000***	***27,825,441***
Asset Condition	10,090,732	10,941,238	14,253,000	13,065,303	7,201,000	5,830,800
Non-Infrastructure	242,600	284,808	168,000	(590,138)	685,000	705,603
System Capacity & Performance	16,707,000	14,595,922	22,434,000	17,454,290	8,635,000	10,758,714
Total Non-Discretionary	27,040,332	25,821,968	36,855,000	29,929,455	16,521,000	17,295,117
Grand Total	**57,659,000**	**55,339,166**	**68,500,000**	**58,272,473**	**46,900,000**	**45,120,558**
Vegetation Management	-	7,857,000	-	6,882,000	-	4,829,000
Inspection & Maintenance Program	-	-	-	-	-	-

` Spending Rationale	FY 2012 Budget	FY 2012 Actual	FY 2013 Budget	FY 2013 Actual	FY 2014 Budget	FY 2014 Actual
Statutory/Regulatory	21,636,500	13,075,154	20,006,000	10,410,223	16,509,000	17,137,642
Damage/Failure	9,705,000	12,992,859	10,422,000	17,515,452	10,050,000	14,373,392
Total Discretionary	***31,341,500***	***26,068,013***	***30,428,000***	***27,925,675***	***26,559,000***	***31,511,034***
Asset Condition	12,318,050	11,520,099	11,863,000	8,070,832	20,242,000	20,904,838
Non-Infrastructure	278,000	266,545	336,000	2,269,065	255,000	(346,246)
System Capacity & Performance	17,962,450	13,955,240	13,913,000	11,249,210	12,544,000	25,972,338
Total Non-Discretionary	30,558,500	25,741,884	26,112,000	21,589,107	33,041,000	46,530,930
Grand Total	**61,900,000**	**51,809,897**	**56,540,000**	**49,514,782**	**59,600,000**	**78,041,964**
Vegetation Management	9,826,000	8,176,000	8,256,000	8,248,749	8,476,000	8,529,815
Inspection & Maintenance Program	2,479,230	1,465,884	2,270,900	1,480,205	3,779,000	3,611,958

` Spending Rationale	FY 2015 Budget	FY 2015 Forecast	FY 2016 Proposed
Customer Request/Public Requirements	14,537,000	18,493,000	15,647,000
Damage/Failure	9,816,000	16,109,000	11,177,000
Total Discretionary	***24,353,000***	***34,602,000***	***26,824,000***
Asset Condition	19,511,000	22,191,000	24,053,000
Non-Infrastructure	277,000	399,000	275,000
System Capacity & Performance	21,759,000	24,084,000	22,148,000
Total Non-Discretionary	41,547,000	46,674,000	46,476,000
Grand Total	**65,900,000**	**81,276,000**	**73,300,000**
Vegetation Management	7,726,000	8,222,000	8,884,000
Inspection & Maintenance Program	2,995,000	2,795,000	3,333,000

APPENDIX 3

FY2016 ISR Plan PowerServices Adjustments
Capital Outlays by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASS	FY2016 Initial Proposed Budget (10-10-14)	FY2016 PowerServices Adjustment		FY2016 Final Proposed Budget (12-23-15)
Customer Request/ Public Requirements	3rd Party Attachments	254,000	(100,000)		154,000
	Distributed Generation	645,000			645,000
	Land and Land Rights - Dist	167,000			167,000
	Meters – Dist	1,775,000			1,775,000
	New Business - Commercial	4,213,000			4,213,000
	New Business - Residential	3,500,000			3,500,000
	Outdoor Lighting - Capital	711,000			711,000
	Outdoor Lighting - Capital MV	-			-
	Public Requirements	1,602,000			1,602,000
	Transformers & Related Equipment	2,880,000			2,880,000
Statutory/Regulatory Total		**15,747,000**	**(100,000)**		**15,647,000**
Damage/ Failure	Damage/ Failure	10,177,000			10,177,000
	Major Storms – Dist	1,000,000			1,000,000
Damage/Failure Total		**11,177,000**			**11,177,000**
Subtotal Non-Discretionary		**26,924,000**	**(100,000)**		**26,824,000**
Asset Condition	Asset Replacement				
	URD Cable Strategy	3,300,000	(800,000)		2,500,000
	UG Cable Replacement	1,498,000	(500,000)		998,000
	Metalclad Switchgear	1,910,000	(370,000)		1,540,000
	Substation Transformer Replacement	1,300,000	(530,000)		770,000
	Flood Mitigation	600,000			600,000
	Southeast	50,000			50,000
	South Street	4,560,000			4,560,000
	Others	5,730,000			5,730,000
	Asset Replacement Total	18,948,000	(2,200,000)		16,748,000
	Asset Replacement - I&M (NE)	7,605,000	(900,000)		6,705,000
	Safety	600,000			600,000
Asset Condition Total		**27,153,000**	**(3,100,000)**		**24,053,000**
Non-Infrastructure	General Equipment	100,000			100,000
	Telecommunications Capital - Dist	175,000			175,000
Non-Infrastructure Total		**275,000**			**275,000**
System Capacity and Performance	Load Relief	18,074,000			18,074,000
	Reliability	4,074,000			4,074,000
System Capacity and Performance Total		**22,148,000**	**-**		**22,148,000**
Subtotal Discretionary		**49,576,000**	**(3,100,000)**		**46,476,000**
Total Electric Distribution		**76,500,000**	**(3,200,000)**		**73,300,000**
Vegetation Management Program	Cycle Trimming	5,414,000	(1,854,181)	(4)	5,414,000
	Hazard Tree	1,150,000	(150,000)	(1)	1,000,000
	Sub-T	220,000			220,000
	Police/Flagman Detail	750,000			750,000
	All Other Activities	1,500,000			1,500,000
Vegetation Management Program Total		**9,034,000**	**(150,000)**		**8,884,000**
Inspection and Maintenance Program	Operation and Maintenance Expenses:				
	Opex related to Capex	1,910,000	(25,000)	(2)	1,885,000
	Repair - Related Costs				-
	Inspections and Repair- Related Costs	1,423,000			1,423,000
	Removal Costs	1,146,000	(207,000)	(3)	939,000
	System Planning & Protection Coordination Study		25,000		25,000
Inspection and Maintenance Program Total		**4,479,000**			**4,272,000**
Grand Total ISR- All Programs		**90,013,000**	**(3,350,000)**		**86,456,000**

FOOTNOTE (1) Excludes $1.8M cost recovery for Verizon
FOOTNOTE (2) $25K for System Planning Study shown separately. No net change to category.
FOOTNOTE (3) Not an adjustment; Company's proposed budget is lower than originally submitted
FOOTNOTE (4) PowerServices recommended adjustment to account for Verizon responsibility for all vegetation management categories
The amount shown reflects a decrease in recovery from ratepayers.
The proposed National Grid FY 2016 ISR Plan filed on 12/23/14 does not reflect this adjustment

APPENDIX 4

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 11-56 November 14, 2013

Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Recovery of December 2008 Storm Costs.

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3. Analysis and Findings

Before National Grid may recover Storm costs from ratepayers, the Company has the burden to demonstrate that (1) those costs are reasonable and were prudently incurred; and (2) it is not seeking recovery from ratepayers of costs that should be borne by Verizon. D.P.U. 09-39, at 212-213; D.P.U. 11-56, Interlocutory Order at 5.

The JOA, which incorporates IOPs, is a contractual document that the Company has entered into with Verizon with respect to the joint ownership of poles (Exhs. AG-2, at 2 & Art. 3; AG-1, at IOP § J). IOP § J includes provisions with respect to vegetation management cost-sharing between the Company and Verizon, including but not limited to preventive maintenance trimming and Heavy Storm Work (Exh. AG-1, at IOP § J). Although Verizon was not a party in this proceeding, the parties offer opposing interpretations of IOP § J to support their positions on whether and to what extent Verizon is responsible for vegetation management, including Heavy Storm Work.

In the instant matter, we need not reach a determination on the interpretation of IOP § J as it pertains to cost-sharing responsibilities between National Grid and Verizon for Heavy Storm Work because the Company has not demonstrated that it prudently sought agreement with Verizon to share the Winter Storm 2008 Heavy Storm Work costs.[21] The Company has the

21 In addition, the parties have failed to demonstrate that the Department is the appropriate forum for determining vegetation management cost-sharing responsibilities between National Grid and Verizon under IOP § J. Although the JOA is relevant to determination of an issue before us, the JOA is not a contract that has been submitted to the Department for review and approval. Moreover, the parties have not demonstrated how interpretation of a contract between National Grid and a non-party telecommunications utility is appropriate here, particularly given that Verizon is not a party to this proceeding. Although when interpreting a contract the Department gives effect to the agreement's plain language and gives terms their usual and ordinary meeting, we are left with little

burden to demonstrate that it prudently incurred all storm-related costs. D.P.U. 11-01/11-02, at 50, 56; D.P.U. 11-56, Interlocutory Order at 5; D.P.U. 09-39, at 212-213. In the instant case, there is no evidence that the Company approached Verizon with respect to Heavy Storm Work vegetation management cost-sharing responsibilities for Winter Storm 2008 (see Exhs. NG-Rebuttal-Revised at 25-26; AG1-8; DPU 1-5(d)). The Company concedes that it has no documentation with Verizon regarding negotiating Winter Storm 2008 vegetation management cost-sharing obligations (Tr. 1, at 130-131). Moreover, the Company has not billed Verizon for any Winter Storm 2008 Heavy Storm Work, nor is there evidence that the Company has taken any other action to try to recover any costs from Verizon (Exhs. DPU 1-5 (c); DPU 1-5(d)). Although National Grid acknowledges that IOP § J requires Company and Verizon field representatives to determine as soon as practicable what lines and to what extent each will participate in costs incurred from Heavy Storm Work, the Company has not demonstrated that it even attempted to reach agreement with Verizon with respect to these costs (see Exh. DPU 1-5(d)). Instead, the Company states that Verizon has a longstanding position that it is not responsible for these costs and routinely declines to participate in them (Exhs. NG-Rebuttal-Revised at 25-26; DPU 1-5(d)).

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recourse if the plain language is ambiguous, there is no evidence of the intent of the parties, and one party to the contract is not a party to the proceeding before us. See Southern Union Co. v. Department of Public Utilities, 458 Mass. 812, 820-821 (2011) (citations omitted). Here, the record is devoid of any evidence regarding the intent of the parties with respect to the agreement. Thus, in this instance, we conclude that the Department is not the appropriate forum in which to determine application of the JOA as it pertains to an electric distribution utility and a non-party, non-jurisdictional telecommunication utility. See G.L. c. 164, §§ 94, 94A, 94B. Rather, the Department concludes that the proper forum for interpreting issues with respect to the JOA and IOP § J is the courts.

We do not accept that Verizon's long-standing unwillingness to share in these costs absolves the Company of responsibility to, at a minimum, attempt to negotiate and seek agreement from Verizon for reimbursement of a portion of the Heavy Storm Work costs. Because the Company cannot demonstrate that it took any action following Winter Storm 2008 to reach agreement with Verizon with respect to Heavy Storm Work cost sharing, we conclude that the Company acted imprudently.

We note that other companies have billed and pursued Verizon in court for storm-related vegetation management costs pursuant to their respective JOAs. For example, WMECo previously billed Verizon $267,649 for Winter Storm 2008 vegetation management costs pursuant to WMECo's JOA with Verizon. Western Massachusetts Electric Company, D.P.U. 10-70, at 68-69 (2011).[22] Additionally, on August 14, 2013, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") filed a complaint in Suffolk Superior Court alleging breach of contract, breach of implied covenant of good faith and fair dealing, and unjust enrichment in violation of G.L. c. 93A for Verizon's failure to pay Unitil for joint pole expenses incurred by Unitil, including vegetation management expenses. Fitchburg Gas and Electric Light Company, D.P.U. 13-90, Exh. AG 1-82 & Att.[23] We expect all electric distribution companies to take prudent steps to seek recovery from Verizon for vegetation management costs, including, if necessary, pursuing recovery of those costs in court, before seeking recovery of those costs from

22 Verizon requested reimbursement of $80,417 from WMECo for similar expenses. D.P.U. 10-70, at 68-69.

23 The Department's investigation in D.P.U. 13-90 is ongoing.

electric ratepayers. If a company fails to collect vegetation management costs from Verizon following an adjudicated court proceeding, it may then file for recovery of those costs here.

The Company seeks recovery of $10,081,997 in costs associated with vegetation management efforts relating to the Winter Storm 2008 (Exh. DPU 1-1 (b)). Absent demonstration that the Company has taken prudent steps to seek agreement regarding Heavy Storm Work costs, bill Verizon for such work and, if necessary, pursue Verizon in court for storm-related vegetation management costs, we disallow 50 percent of the Winter Storm 2008 vegetation management costs[24] associated with the percentage of poles in National Grid's service territory that it jointly owns with Verizon.[25] We therefore direct the Company to submit within 30 days of this Order a compliance filing demonstrating that it has applied a 50 percent disallowance to vegetation management costs to the portion of poles National Grid jointly owns with Verizon. If National Grid pursues Verizon in court for collection of Winter Storm 2008 vegetation management costs, and if Verizon is adjudicated as not being responsible for all or any portion of the costs that we disallow here, National Grid may then submit a filing with the Department seeking recovery of those costs.

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24 We disallow 50 percent of these costs based upon what we conclude to be an amount potentially subject to recovery from Verizon in court under an interpretation of IOP § J.

25 The record is unclear whether National Grid and Verizon jointly own all or just some of the poles in National Grid's service territory (<u>see</u> Exhs. AG 1-92; AG 1-93; AG 1-94).

APPENDIX 5

JOINT OWNERSHIP AGREEMENT BETWEEN NARRAGANSETT ELECTRIC COMPANY (PARENT COMPANY – NATIONAL GRID) AND VERIZON – NEW ENGLAND INC

OCTOBER 1, 1980
AMENDED SEPTEMBER 25, 2001

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Riqhts and Obligations: IOP's	Article 3: To carry out the purpose of this Agreement to facilitate the joint ownership of poles and anchors, the Agreement sets forth the rights and obligations of the Companies with respect to such ownership, including without limitation their rights and obligations with respect to the following matters:

4. Allocation of ownership and allocation of space
B. Division of costs and expenses
C. Acquisition of joint ownership
D. Construction standards
E. Performance of work
F. Payment and billing
G. Custody and maintenance areas
H. Changes in character of circuits
I. Termination of joint ownership
J. Administration of Agreement

Certain of the basic contractual provisions of this Agreement are not set forth in the body of the Agreement, but are set forth with operational or administrative procedures in Intercompany Operating Procedures (IOP's). IOP's in effect at any time shall be attached hereto and **shall** be a part of this Agreement. The IOP's in effect or taking effect upon the effective date of this Agreement are listed in Appendix A attached hereto.

The provisions of IOP's in effect at any time shall be subject to review upon the written request of either company given to the other. Amendments to IOP's including elimination of any effective IOP's or addition of new IOP's, shall be made effective by written instrument signed on behalf of each company by a duly authorized officer of such company or by some other duly authorized representative designated herein or by written notice to the other company.

Work Responsibility	Article 4: The placing of new Jointly Owned poles, guys, and anchors, and the replacing, relocating or removing of existing Jointly Owned poles, guys, and anchors shall be divided equitably between the companies. The work performed by each company shall be subject to mutal agreement, in writing, as set forth in attached Intercompany Operating Procedures (IOP's).

Term of Agreement	Article 18: This Agreement shall continue in force for two (2) years from the date of execution and thereafter until terminated by either company by not less than one (1) year's notice in writing to the other company, but provisions of this Agreement relating to poles Jointly Owned shall nevertheless continue in full force and effect as to such poles until Joint Ownership thereof is terminated.
Waiver of Portions of Agreement	Article 19: The failure of either company to enforce or insist upon compliance with any of the terms or conditions of this agreement, or its waiver of the same in any instance or instances, shall not be construed to be a general waiver or relinquishment of any of such terms or conditions, but the same shall be and remain at all times in full force and effect.
Sole Agreements	Article 22: This document and the Intercompany Operating Procedures constitute the entire Agreement between the parties respecting Joint Ownership of poles, guys, and anchors.

APPENDIX A
1-1-80

NEW ENGLAND ELECTRIC SYSTEM

AND

NEW ENGLAND TELEPHONE AND TELEGRAPH COMPANY

INTERCOMPANY OPERATING PROCEDURES

I.O.P.	SUBJECT
A	ALLOCATION OF SPACE
B	ACQUIRING JOINT OWNERSHIP IN EXISTING POLES
C	ACQUIRING JOINT OWNERSHIP OF NEW POLES
D	GUYS AND ANCHORS
E	RIGHTS OF WAY
F	CUSTODY AND MAINTENANCE
G	JOINT TREE TRIMMING AGREEMENT
H	DIVISION OF COSTS
I	FLAT RATE BILLING SCHEDULES
J	PROCEDURE WHEN CHARACTER OF CIRCUITS IS CHANGED
K	MONTHLY BILLING PROCEDURE
L	REIMBURSEMENTS FOR UNAUTHORIZED POLE ATTACHMENTS
M	TERMINATION OF THE JOINT OWNERSHIP OF A POLE
N	USE OF BOTH SIDES OF J.O. POLES BY THE TELEPHONE COMPANY
O	BILLING FOR REPLACEMENT OF SERVICEABLE POLES DUE TO AN INCREASE IN THE VOLTAGE OF WIRES AND CABLES
P	ACTS OF PUBLIC AUTHORITY
Q	INTERCOMPANY CONTACTS
R	POLICY FOR POLE WORK
S	OVERHEAD LINE EXTENSIONS
T	PREPARATION OF ADDENDA

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AMENDMENT TO INTERCOMPANY OPERATING PROCEDURES

THIS AMENDMENT made this 25 day of September, 2001, by and between Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company and Narragansett Electric Company and Verizon New England Inc.

WITNESSETH

WHEREAS, Granite State Electric Company, Massachusetts Electric Company and Narragansett Electric Company and New England Telephone and Telegraph Company d/b/a Bell Atlantic - New England entered into agreements titled "Intercompany Operating Procedures," dated August 1, 1993 ("IOPs") covering operating procedures for poles they jointly own; and

WHEREAS, In the IOPs, Granite State Electric Company, Massachusetts Electric Company and Narragansett Electric Company were incorrectly identified as "New England Electric"; and

WHEREAS, In the IOPs, New England Telephone and Telegraph Company d/b/a Bell Atlantic - New England was incorrectly identified as "New England Telephone"; and

WHEREAS, National Grid USA, the parent company of Granite State Electric Company, Massachusetts Electric Company and Narragansett Electric Company is now also the parent company of Nantucket Electric company; and

WHEREAS, National Grid USA has acquired Eastern Utility Associates, the parent company of Blackstone Valley Electric Company, Eastern Edison Company and Newport Electric Corporation; and

WHEREAS, On May 1,2000, Blackstone Valley Electric Company and Newport Electric Corporation were merged into Narragansett Electric Company and Eastern Edison Company was merged into Massachusetts Electric Company; and

WHEREAS, the name of New England Telephone and Telegraph Company has been changed to Verizon New England Inc.; and

NOW THEREFORE, in consideration of the premises and mutual covenants contained herein, effective as of the date of this amendment, the parties hereby covenant and agree as follows:

1. The words "New England Electric" shall be replaced with "Granite State Electric Company, Massachusetts Electric Company, Nantucket Electric Company and Narragansett Electric Company" at each place they appear in the IOPs.

2. The words "New England Telephone" shall be replaced with "Verizon New England Inc." at each place they appear in the IOPs.

3. The municipalities formerly served by Blackstone Valley Electric Company, Eastern Edison Company and Newport Electric Company shall be incorporated into the IOPs by amending IOP C,

titled "Custody and Maintenance," by replacing the list of municipalities attached thereto, with the list of municipalities attached hereto. This amended list of municipalities is hereby made a part of IOP C.

4. In all other respects, the IOPs shall continued unaltered.

IN WITNESS WHEREOF, the parties have hereunto caused these presents to be executed by their respective officers thereunto duly authorized, as of the day and year first above written.

VERIZON NEW ENGLAND INC.	GRANITE STATE ELECTRIC COMPANY MASSACHUSETTS ELECTRIC COMPANY NANTUCKET ELECTRIC COMPANY NARRAGANSETT ELECTRIC COMPANY
By: [signature]	By: [signature]
Title: Director OPE WA	Title: Sr VP & Treasurer
Date: 9/25/01	Date: 8/17/01

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INTERCOMPANY OPERATING PROCEDURES IOP J

J. TREE TRIMMING AND CLEARING

It has been agreed the New England Telephone Company and New England Electric System companies will participate in a Joint Tree Trimming arrangement as follows.

All trimming arrangements shall be agreed to on a signed Exchange of Notice Memorandum.

1. Preventive maintenance tree trimming shall be done on a joint basis when both companies have a need.

   When it is agreed that both parties will benefit from such Joint Tree Trimming the division of costs will be 75% Electric Company and 25% Telephone Company.

2. Trimming for line extension along existing roads shall be surveyed in the field and a determination made whether both parties have a need. The division of cost shall be 60% Electric Company and 40% Telephone Company.

3. Trimming for line extensions for off road/right-of-way shall be surveyed in the field and where both parties have a need, division of cost will be 50% Telephone Company and 50% Electric Company.

4. Topping of trees, if they present a hazard to both parties, shall be done jointly at a 50/50 division of cost. Whole trees to be removed with municipalities or private owners at 33 1/3% division of cost for each party or on a fair share basis when more than three parties are involved.

5. Heavy storm work such as hurricanes, wet snow, tornadoes, and ice storms will be handled immediately without prior review. Agreement should be reached by field representatives of the two companies as soon as practicable, after each major storm, to determine which lines and to what extent each party will participate, not withstanding any participation by another party. The parties agree to 50/50 basis for heavy storm work. The parties agree to reciprocal acceptance to each other's tree contractors for heavy storms. Trimming resulting from routine individual storms should be performed jointly at the same division of costs as maintenance trimming. Removal of weakened or topped trees and large limbs which threaten both parties plant should be removed on a 50/50 basis, subject to field review wherever possible.

Power Services
Engineering & Management Services

6. Administration

The Electric Company will annually furnish the Telephone Company a list of areas to be trimmed. The Telephone Company will provide, within 60 days, a suitable list of pole lines or major portions thereof that they want to be trimmed jointly.

Contracts that will exceed $5,000 in cost to the Telephone Company will be awarded to the lowest of at least four qualified bidding contractors.

Each company will annually furnish the other company with a list of its approved Trimming Contractors. Each company will attempt to utilize contractors that are on both companies approved contractor list.

For work done by a Contractor not on both companies' list of approved contractors, the constructing company will pay the full cost of the Trimming Bill and then bill the other company its share of the total cost. Such bill shall be accompanied by a copy of the contractor's bill. The full cost of any unapproved trimming shall be done by the company that arranged for same.

Bills rendered by the Contractor will include percent and cost to Electric Company and percent and cost to Telephone Company and total cost of the job.

Miscellaneous costs associated with trimming such as police protection, tree wardens payment, obtaining permission, state highway inspector will be shared by the joint owners on the same basis as the IOP provides for trimming costs.

7. This arrangement shall continue for five years unless, after 3 years, both parties agree to modify it. This agreement will automatically renew itself each year unless either party notified the other in writing at least 30 days prior to the end of such yearly period that it wishes to modify or terminate the agreement.

Bruce W. [signature]
New England Telephone Company

[signature]
New England Electric System

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