National Grid

The Narragansett Electric Company

Electric Infrastructure, Safety, and Reliability Plan FY 2014 Proposal

December 28, 2012

Docket No. ______

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

nationalgrid

Thomas R. Teehan
Senior Counsel

December 28, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02889

RE: National Grid's Proposed FY 2014 Electric Infrastructure, Safety, and Reliability Plan Docket No. _______

Dear Ms. Massaro:

On behalf of National Grid[1], I have enclosed ten (10) copies of the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year 2014[2]. National Grid has developed this proposed Electric ISR Plan, which is designed to enhance the safety and reliability of the Company's Rhode Island electric distribution system. The proposed Plan was submitted to the Division of Public Utilities and Carriers ("Division") for review. The Company received and responded to discovery requests from the Division and has met with the Division's representatives regarding this proposed Plan. The Division has agreed to the overall spending portion of this plan, but will continue to review and discuss particular Plan provisions, as the Commission conducts its proceeding in this matter.

The Electric ISR Plan is designed to protect and improve the electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, sustaining system viability through targeted investments driven primarily by condition, continuing a level of feeder hardening and cutout replacement, and operating a cost-effective vegetation management program. The Plan is intended to achieve these safety and reliability goals through a cost-effective, comprehensive work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island electric distribution infrastructure and directly benefit all Rhode Island electric customers.

The Plan separates the general categories of work into discretionary and non-discretionary work, and it includes a description of the categories of work the Company proposes to perform in fiscal year 2014 as well as the proposed targeted spending levels for each work category. Along with this cover letter and a copy of the Plan, this filing includes the pre-filed direct testimony of four witnesses. Ms. Jennifer L. Grimsley and Mr. Craig M. Allen testify to introduce the Plan and describe the Plan's large program components. Mr. William R. Richer provides the calculation of the Company's fiscal year 2014 revenue requirement under the Plan. Ms. Nancy Ribot testifies regarding the calculation of the Electric Infrastructure, Safety and Reliability ("ISR") factors proposed in this filing and provides the customer bill impacts of the proposed rate changes. For the average residential customer using 500 kWh per month,

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

[2] The Electric ISR Plan is submitted in compliance with the provisions of R.I.G.L. §39-1-27.7.1.

implementation of the proposed ISR factors will result in a monthly rate increase of $0.16, or 0.2 percent, based upon rates approved in Docket No. 4323.

This Plan that the Company is submitting to the Commission for review and approval presents an opportunity to facilitate and encourage investment in our electric utility infrastructure and enhance its ability to provide safe, reliable, and efficient electric service to customers.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Steve Scialabba
Leo Wold, Esq.
James Lanni

PRE-FILED DIRECT TESTIMONY

OF

JENNIFER L. GRIMSLEY

AND

CRAIG M. ALLEN

December 28, 2012

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I. INTRODUCTION

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

A. My name is Jennifer L. Grimsley. My business address is 40 Sylvan Road, Waltham, Massachusestts 02451.

Q. Ms. Grimsley, by whom are you employed and in what position?

A. I am employed by National Grid USA Service Company, Inc. ("Service Company") as Director, Network Strategy, New England Electric. I am responsible for regulatory filings and regulatory compliance related to electric distribution operation of The Narragansett Electric Company d/b/a National Grid (the "Company" or "National Grid"). I am also responsible for those types of filings relative to National Grid USA's electric distribution operations in Massachusetts.

Q. Ms. Grimsley, please describe your educational background and professional experience.

A. I graduated from Washington University in 1986, earning a bachelor's degree in electrical engineering and from Rivier College in 1991, earning a master's degree in business administration. In 1986, I began my engineering career as an associate engineer with Massachusetts Electric Company ("Mass. Electric") in North Andover. In 1993, I was promoted to district engineering manager for Mass. Electric in Northampton, and have held various engineering and management positions since that time, including Project

Manager for the Reliability Enhancement Program in 2006. In 2007, I became Manager Asset Strategy and Policy and was responsible for developing the strategies to replace distribution assets. I was promoted to Director, Asset Strategy & Policy in 2008. In 2009, I became Executive Advisor to the Chief Operating Officer of Electricity Operations for National Grid USA. In 2011, I assumed my current role as Director, New England Electric Network Strategy.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("Commission")?

A. Yes. I have testified in Docket Nos. 4218, 4237, and 4307.

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

A. My name is Craig M. Allen. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

Q. Mr. Allen, by whom are you employed and in what position?

A. I am employed by the Service Company as Manager, Vegetation Strategy. I am responsible for the design, support, and long term planning of vegetation strategies used on National Grid USA's distribution and transmission assets.

Q. Mr. Allen, please describe your educational background and professional experience.

A. I graduated from the State of New York - College of Environmental Science and Forestry in 1979, earning an Associates degree in Forest Technology and again in 1981, earning a Bachelor's degree in Forest Resource Management. I hold an arborist certification (#NY0710AU) through the International Society of Arborist. I also hold a Utility Specialist certification through that same organization. I began working for Niagara Mohawk Power Corporation in 1982. I have held various positions in utility vegetation management including Regional Supervisor, Regional Superintendent, System Arborist, Manager of Forestry Delivery, and Manager of Distribution Vegetation Strategy. I assumed my current role as Manager of Vegetation Strategy (T&D) in June of 2011.

Q. Have you previously testified before the Commission?

A. Yes. I have testified in Docket Nos. 4307 and 4218.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to present the plan developed by the Company and reviewed by the Rhode Island Division of Public Utilities and Carriers (the "Division") regarding the Company's proposed fiscal year ("FY") 2014 Electric Infrastructure, Safety, and Reliability ("ISR") Plan (the "Electric ISR Plan" or the "Plan")[1]. As is described in the Plan document, implementation of the Electric ISR Plan will allow the Company to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable cost. The proposed Electric ISR Plan document is Exhibit 1 to this testimony.

Q. Please summarize the categories of infrastructure, reliability, and safety spending covered by the Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2014, or the twelve month fiscal year ending March 31, 2014: capital spending on electric infrastructure projects; operation and maintenance ("O&M") expenses for vegetation management ("VM"); and O&M expenses for an inspection and maintenance ("I&M") program. The Division has agreed to the spending portion of this plan and will continue to review particular plan provisions as the Commission conducts its proceeding in this matter.

Q. Please explain how the Electric ISR Plan is structured.

A. The Electric ISR Plan, which is provided as Exhibit 1 to this testimony, encompasses the electric infrastructure, safety, and reliability spending plan for FY 2014, as well as an annual rate reconciliation mechanism that would provide for recovery related to capital

[1] The Electric ISR Plan presented in this filing is the third annual plan submitted to the Commission pursuant to the

investments and other spending undertaken pursuant to the annual pre-approved budget for the Electric ISR Plan. The Electric ISR Plan itemizes the recommended work activities by general category and provides budgets for capital investment, as well as O&M expenses for a VM program and an I&M program. After the end of the fiscal year, the Company would true up the ISR Plan's projected capital and O&M expense levels used for establishing the revenue requirement to actual or allowed investment and expenditures on a cumulative basis and reconcile the revenue requirement associated with the actual investment and expenditures to the revenue billed from the rate adjustments implemented at the beginning of each fiscal year.

III. CAPITAL INVESTMENT PLAN

Q. How has the Company formulated the Capital Investment Plan for review by the Commission?

A. The Company's FY 2014 Electric ISR Plan was prepared by the Company and submitted to the Division for review. The Company received and responded to discovery requests from the Division and had meetings and discussions with the Division's representatives and its consultant, Mr. Greg Booth, regarding this proposed Plan. The Division has agreed to the overall spending portion of this Plan, and will continue to review particular Plan provisions as the Commission conducts its proceeding in this matter. In this filing, the Company is putting forth a capital spending plan for FY 2014 in the amount of $59.6

provisions of R.I.G.L. §39-1-27.7.1.

million, encompassing a range of project work that is needed to maintain safe and reliable service. The project work that is included in the Electric ISR Plan is specifically designed to meet system performance objectives and/or customer service requirements, which the Company must address as part of its public service obligation. In the Plan, attached as Exhibit 1, the Company has provided a detailed explanation of the categories of investment that it plans to undertake, the factors motivating the nature and amount of investment to be completed, and the specific projects that will be undertaken in Rhode Island.

Q. Please describe the categories of work activities that are included in the Electric ISR Plan to protect service reliability.

A. The Company's overall objective in preparing the Electric ISR Plan is to arrive at a capital spending plan that is the optimal balance in terms of making the investments necessary to improve the performance of discreet aspects of the system thereby resulting in maintaining the overall reliability of the system, while also ensuring a cost-effective use of available resources. Therefore, the Plan includes the capital investment needed to: (1) meet state and federal regulatory requirements applicable to the electric system; (2) repair failed or damaged equipment; (3) address load growth/migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by condition. These categories of investment constitute the core of work required for the Company to meet its public-service obligation in Rhode Island and, for this reason the Company has included these categories in its proposal to be approved by the Commission.

Q. Please review the FY 2013 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2013 are associated with five key work categories: Statutory/Regulatory, Damage Failure, System Capacity and Performance, Asset Condition, and Non-infrastructure. The Chart below summarizes the proposed spending level for each of these key driver categories proposed for FY 2014, as follows:

Proposed FY 2014 Capital Investment by Key Driver Category

SPENDING RATIONALE	**FY 2014 PROPOSED BUDGET**	**%**
Statutory/Regulatory	$16,509,000	28%
Damage/Failure	$10,050,000	17%
Subtotal	*$26,559,000*	*45%*
Asset Condition	$20,242,000	33%
Non-Infrastructure	$255,000	1%
System Capacity and Performance	$12,544,000	21%
Subtotal	*$33,041,000*	*55%*
Grand Total	**$59,600,000**	100%

As shown, a significant portion of the investment for capital projects in FY 2014 are necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates (i.e. $16.5 million, or 28 percent). These investments arise from the Company's regulatory, governmental, or contractual obligations, such as responding to new customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by the Rhode Island Department of Transportation ("RIDOT"). For the most part, the scope and timing of this work is defined by others external to the Company.

The need to repair failed and damaged equipment equates to approximately $10.1 million, or 17 percent, of the Company's investment. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes.

The Plan designates the investment necessary to comply with statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and "non-discretionary" in terms of scope and timing. Together, these items account for approximately $26.6 million, or 45 percent, of proposed capital investment in FY 2014. Since the 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. As such, mandatory, or non-discretionary, capital investments are to be recovered through a capital rate adjustment mechanism that reconciles the plant in service amounts associated with this projected spending to the lesser of actual plant in service or actual spending on a cumulative basis following the close of the fiscal year.

The system capacity, asset condition, and non-infrastructure projects that the Company will pursue in FY 2014 have been chosen to maintain the overall reliability of the system and collectively amount to approximately $33.0 million, or 55 percent of the Company's proposed FY 2014 capital investment. System capacity and performance projects are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers. Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the Company's system and capacity loading policy. These projects are designed to reduce the degradation of equipment's service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

In addition to accommodating existing load and load growth/migration, the investments in this category are used to install new equipment, such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with system events. This category also includes investment to improve the overall performance of the network that is realized by the reconfiguration of feeders and the installation of feeder ties. System capacity and performance projects account for approximately $12.5 million, or 21 percent, of the proposed capital investment in FY 2014.

Projects necessary due to the poor condition of infrastructure assets account for about $20.2 million, or 33 percent, of the proposed capital investment in FY 2014. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the prospect for reliability issues. Moreover, the large number of aged assets in the Company's service area, as well as Company and industry-wide experience, requires the Company to develop strategies to replace assets based on the condition of those assets to avoid the prospect that a large number of similar assets will fail at the same time or within short windows of time.

Finally, the non-infrastructure category of investment represents those capital expenditures that do not fit into one of the foregoing categories, such as general and telecommunications equipment, but which are necessary to run the electric system. In total, capital investment for non-infrastructure projects will account for about $255,000 or less than one percent of capital investment in FY 2014.

Q. Is the Company able to provide the Commission with detail on the specific projects that will be undertaken in each of the work categories covered in the Electric ISR Plan?

A. Yes. In the Plan, the Company has provided detail on the specific projects within each work category that would be undertaken in FY 2014 as part of the Electric ISR Plan. The Company and the Division have reviewed these planned projects, as well as overall spending levels, and have come to consensus as to the appropriate investment levels for FY 2014.

Q. Throughout the fiscal year, will the Company provide periodic updates regarding the various categories of capital work that are included in an approved Electric ISR Plan?

A. Yes. The Company will provide quarterly reports with the Division and Commission on the progress of its Electric ISR Plan programs. Additionally, the Company will provide an annual report on the prior fiscal year's activities at the time it makes its reconciliation and rate adjustment filings. The Company and the Division are aware that in executing the approved Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original plan. In such cases, the Company will include an explanation of any significant deviations in its quarterly reports and in its annual year-end report.

IV. VEGETATION MANAGEMENT PROGRAM

Q. Could you briefly review the FY 2014 spending levels for the Company's VM Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service to customers?

A. Yes. The VM Program that the Company has reviewed with the Division is carefully balanced to implement the program aspects to a degree and in a manner that will achieve the reliability benefits sought by the Company without unduly burdening customers. After discussion with the Division, the Electric ISR Plan allows for approximately $8.5 million in VM spending for FY 2014.

V. INSPECTION AND MAINTENANCE PROGRAM

Q. What are the reliability benefits associated with the Company's I&M Program?

A. The Electric ISR Plan incorporates the implementation of an inspection program for overhead and underground distribution infrastructure to achieve the objective of maintaining safe and reliable service to customers in the short and long term. The I&M Program is designed to provide the Company with comprehensive system-wide information on the condition of overhead and underground system components. The I&M program also includes a component for a Contact Voltage Program as ordered in Docket No. 4237.

Q. Could you briefly review the FY 2014 spending levels for the I&M Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service?

A. The Company proposes an I&M Program O&M expense budget of approximately $3.5 million for FY 2014.

VI. CONCLUSION

Q. In your opinion, does the FY 2014 Electric ISR Plan fulfill the requirements established in relation to the safety and reliability of the Company's electric distribution system in Rhode Island?

A. Yes. The Electric ISR Plan for FY 2014 is designed to establish the capital investment, VM, and I&M activities in Rhode Island that are necessary to meet the needs of its customers and maintain the overall safety and reliability of the Company's electric distribution system. The Electric ISR Plan was presented to the Division and reviewed with the Division and its expert advisor, Mr. Greg Booth, of Power Services. Subsequent to this review, adjustments were made to the Electric ISR Plan in light of the Division's input, with the result being an optimal balance between system reliability and cost. In the end, the Commission's approval of the proposed FY 2014 Electric ISR Plan is essential to enabling the Company to maintain a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

National Grid

The Narragansett Electric Company

Electric Infrastructure, Safety, and Reliability Plan FY 2014 Proposal

December 28, 2012

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Section 1

Introduction and Summary

FY 2014 Electric ISR Plan

Introduction and Summary
FY 2014 Proposal

National Grid[1] has developed the following proposed fiscal year 2014 ("FY 2014") electric Infrastructure, Safety, and Reliability plan (the "Electric ISR Plan" or "Plan") in compliance with Rhode Island's statute providing for an annual electric "infrastructure, safety, and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget."[2] The proposed FY 2014 Electric ISR Plan addresses the following categories of costs as specified in R.I.G.L. §39-1-27.7.1(d): capital spending on electric infrastructure; operation and maintenance ("O&M") expenses on vegetation management; O&M expenses on system inspection; and other costs relating to maintaining safety and reliability of the electric distribution system. In addition, the Electric ISR Plan also includes a discussion of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program ("Contact Voltage Program"), mandated by R.I.G.L. §39-2-25 and approved by the Commission in Docket No. 4237.[3]

The proposed Plan that the Company is submitting for its electric distribution operations is the product of a collaborative effort with the Rhode Island Division of Public Utilities and Carriers ("Division"). The Plan is designed to maintain and upgrade the Company's electric delivery system through repairing failed or damaged equipment, addressing load

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1 The Narragansett Electric Company d/b/a National Grid hereinafter referred to as "National Grid" or the "Company."
2 R.I.G.L. §39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.
3 R.I.G.L. §39-2-25 (6)(c).

growth/migration, sustaining asset viability through targeted investments driven primarily by condition, increasing levels of inspection and maintenance with the completion of the feeder hardening program, and operating a cost-effective vegetation management program. The Company now submits this Plan to the Rhode Island Public Utilities Commission ("Commission") for final review and approval.[4]

This Introduction and Summary presents an overview of the proposed FY 2014 Plan for the above-referenced categories of costs, a description of how the Company proposes to calculate a revenue requirement, a description of how the Company will calculate new rates, and customer bill impacts. The revenue requirement and rate design in this proposal is consistent with the provisions of the Amended Settlement Agreement filed in Docket No. 4323, which the Commission approved on December 20, 2012.

The Electric ISR Plan provides a description of the Company's proposed electric distribution system safety and reliability activities along with its proposed investments and expenditures contained in the Plan for FY 2014 and in conjunction with the establishment of base rates in Docket No. 4323. The proposed Plan itemizes the recommended work activities by general category and provides budgets for capital investment, as well as O&M expenses for a vegetation management program and an inspection and maintenance program.

Consistent with the statute, after the end of the fiscal year, the Company will true up the Electric ISR Plan's projected capital and O&M levels used for establishing the revenue requirement to actual or allowed investment and expenditures, and reconcile the revenue

[4] R.I.G.L. §39-1-27.7.1 (d) provides that the Company and the Division are to work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which would then be submitted for Commission review and approval.

requirement to the revenue billed from the rate adjustments implemented at the beginning of the fiscal year.

As approved in R.I.P.U.C. Docket No. 4218, the Company will continue to file quarterly reports with the Division and Commission on the progress of its Electric ISR Plan programs and when it makes its reconciliation and rate adjustment filing, it will file the annual report on the prior fiscal year's activities. The Company is cognizant that, in executing the Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original Electric ISR Plan. In such cases, the Company will include an explanation of any significant deviations in its quarterly reports and in its annual year-end report.

The FY 2014 levels of net capital investment, vegetation management O&M expense, and inspection and maintenance program O&M expense contained in the Company's proposed Plan are $59.6 million[5], $8.5 million, and $3.8 million, respectively. Included within the Company's O&M inspection and maintenance costs are costs associated with the Company's Contact Voltage Program.

The details of the remaining sections of this proposed Plan are as follows: Section 2 contains the Company's proposed capital investment plan for FY 2014; Section 3 contains the Company's proposed vegetation management program; Section 4 contains the Company's proposed inspection and maintenance program. Section 5 includes a description of how the Company has calculated the FY 2014 Electric ISR Plan revenue requirement; Section 6 includes

[5] Only the incremental amount of capital additions above the amounts included in rate base in Docket 4323 shall be reflected in the revenue requirement calculation for ISR purposes.

a description of how the Company proposes to calculate proposed rates consistent with the final revenue requirement; and Section 7 provides the bill impacts associated with the proposed rates.

Electric Capital Investment Plan

The Company's proposed electric capital investment plan contained in Section 2 summarizes capital investments by key drivers, describes the development of the capital plan, and outlines the large programs and projects contained in the Plan. For purposes of the ratemaking treatment of capital spending, the Company proposes that capital investments used for establishing rates for FY 2014 be those investments in electric distribution infrastructure assets that are projected to be actually placed into service during the applicable fiscal year. The Company has used its capital budget to identify the relevant projects that would be part of the FY 2014 Electric ISR Plan and to provide its rationale for the need for, and benefit of, performing that work to provide safe and reliable service to its customers.

Vegetation Management

Section 3 of this proposal contains the Company's vegetation management O&M expense for FY 2014 and a discussion of the nature of the work anticipated to be performed and the expected benefits. Under the Company's proposed plan, the O&M expense associated with vegetation management activities is the amount estimated to be expended for FY 2014. This estimated amount would be subject to true-up to actual vegetation management O&M expense.

Inspection and Maintenance Program

The Company has also estimated the O&M expense associated with the inspection and maintenance program for FY 2014. Section 4 of this proposal provides details of the proposed inspection and maintenance program for FY 2014. This section is being expanded in this year's filing to include all inspection and maintenance costs for the Company's Contact Voltage Program based on the Company's recommendation filed with the Commission on December 17, 2012 in Docket No. 4237. As with the other projected spending provided in this proposed plan, this estimated amount will be subject to true-up to actual inspection and maintenance O&M expense.

Electric Revenue Requirement

As noted above, Section 5 provides a description of how the Company proposes to calculate the revenue requirement based on the projected incremental net infrastructure investment, excluding any amounts included in rate base in Docket No. 4323, and the total annual vegetation management and inspection and maintenance O&M. This section includes a description of the revenue requirement model that will be used to support the final revenue requirement. The calculation includes the pre-tax rate of return on rate base ultimately approved by the Commission in Docket No. 4323.

Rate Design

Once the revenue requirement is calculated, it will then be appropriately allocated to the Company's rate classes. As mentioned above, the rate design in this proposal is consistent with the provisions of the general base rate proceeding Amended Settlement Agreement in Docket

No. 4323, which the Commission approved on December 20, 2012. The rate design and a summary of proposed rates is presented in Section 6. The following provisions will apply for purposes of rate design:

a. The adjusted revenue requirement associated with the incremental net capital investments will be allocated to rate classes based upon the allocation of rate base to each rate class as approved in the allocated cost of service in Docket No. 4323, the Company's general rate case. For non-demand-based rate classes, the allocated adjusted revenue requirement will be divided by the applicable fiscal year forecasted kWh deliveries for each rate class, arriving in a per-kW factor unique to each rate class. For demand-based rate classes, the allocated adjusted revenue requirement will be divided by estimated billing demand based on a historical load factor applied to the applicable fiscal year forecasted kWh deliveries for each rate class, resulting at a per-kW factor unique to each rate class.

b. The revenue requirement associated with the vegetation management and inspection and maintenance programs will be allocated to rate classes based upon the allocation of operations and maintenance expenses contained in the approved allocated cost of service in Docket No. 4323. For all rate classes except Rates B-62/G-62, the allocated revenue requirement will be divided by the applicable forecasted kWh deliveries for each rate class, arriving at a per-kWh factor unique to each rate class.

For Rates B-62/G-62, the allocated revenue requirement will be divided by estimated billing demand based on a historical load factor applied to the applicable forecasted kWh deliveries for each rate class, resulting in a per-kW factor for the rate class. The Company will then develop proposed rates under the Plan.

Bill Impacts

The bill impacts associated with the proposed rates are presented in Section 7.

Section 2

Electric Capital Investment Plan

FY 2014 Electric ISR Plan

Electric Capital Investment Plan
FY 2014 Proposal

Background

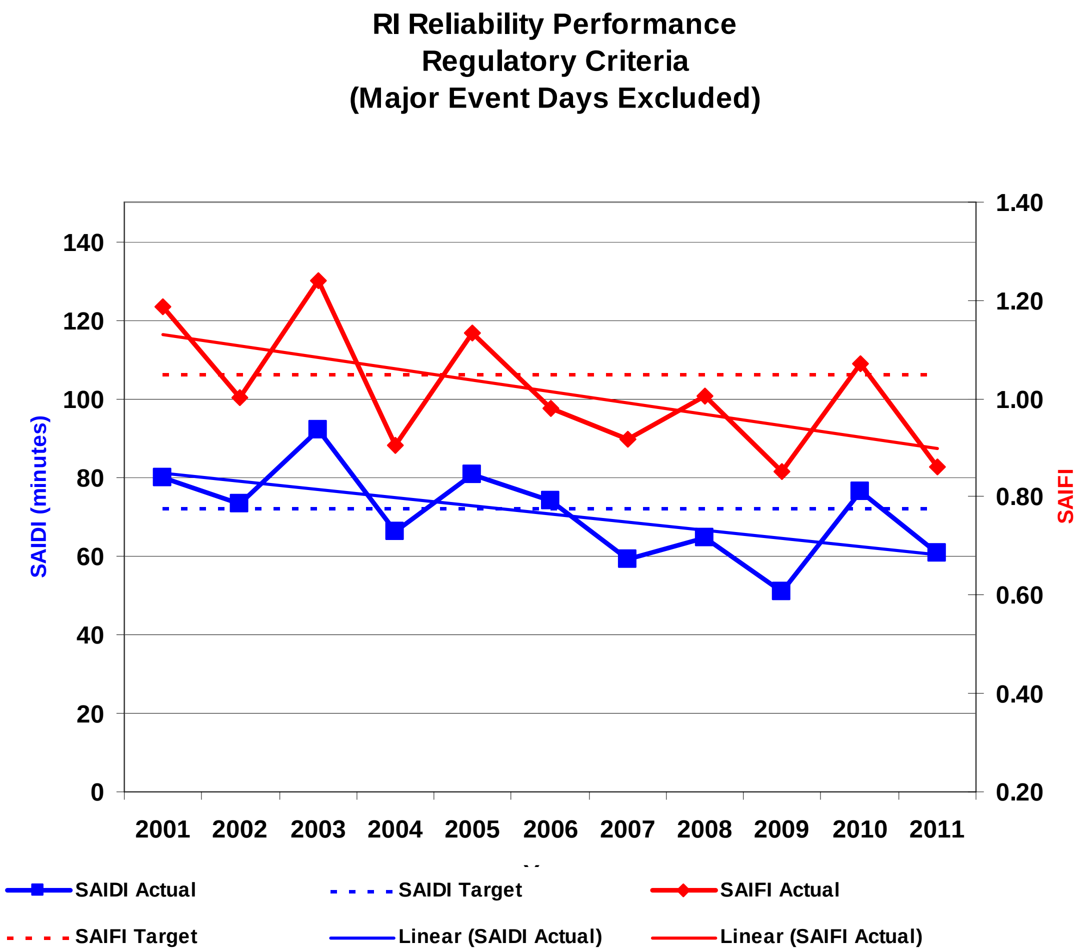
The Company[6] developed its proposed Electric Capital Investment Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs. The Plan includes capital investment needed to (1) meet state and federal regulatory requirements applicable to the electric system; (2) repair failed or damaged equipment; (3) address load growth/migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by condition.

As shown below in Chart 1, the Company met both its SAIFI and SAIDI performance metrics in Calendar Year ("CY") 2011, with SAIFI of 0.86, against a target of 1.05, and SAIDI of 60.7 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days[7]. A comparison of reliability performance in CY 2011 relative to that of previous years demonstrates that the Company's performance has shown a downward (improving) trend over the past several years with major event days excluded.

6 The Company delivers electricity to 484,461 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 Rhode Island cities and towns. To provide this service, the Company owns and maintains 5,385 miles of overhead and 1,105 miles of underground distribution and sub-transmission circuit in a network that includes 98 sub-transmission lines and 400 distribution feeders. The Company relies on 67 substations that house 133 power transformers and 838 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 280,977 distribution poles, 4,242 manholes and 64,403 overhead (pole-mounted) and underground (padmounted or in vaults) transformers.

7 A Major Event Day (MED) is defined as a day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a MED threshold value (4.43 minutes for 2011). For purposes of calculating daily system SAIDI any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.

Chart 1: Reliability Performance



Still, reliability performance primarily depends on the stresses placed on the network from weather conditions and the ability of the system to tolerate those stresses. Chart 2 shows the interruption cause by percent for number of events, customers interrupted and customer minutes interrupted, excluding defined major event days. Chart 3 shows the same information including defined major event days. In both charts, deteriorated equipment and trees are the top two drivers affecting customers interrupted.

Chart 2: Customer Interruptions by Cause (excluding PUC Major Event Days)

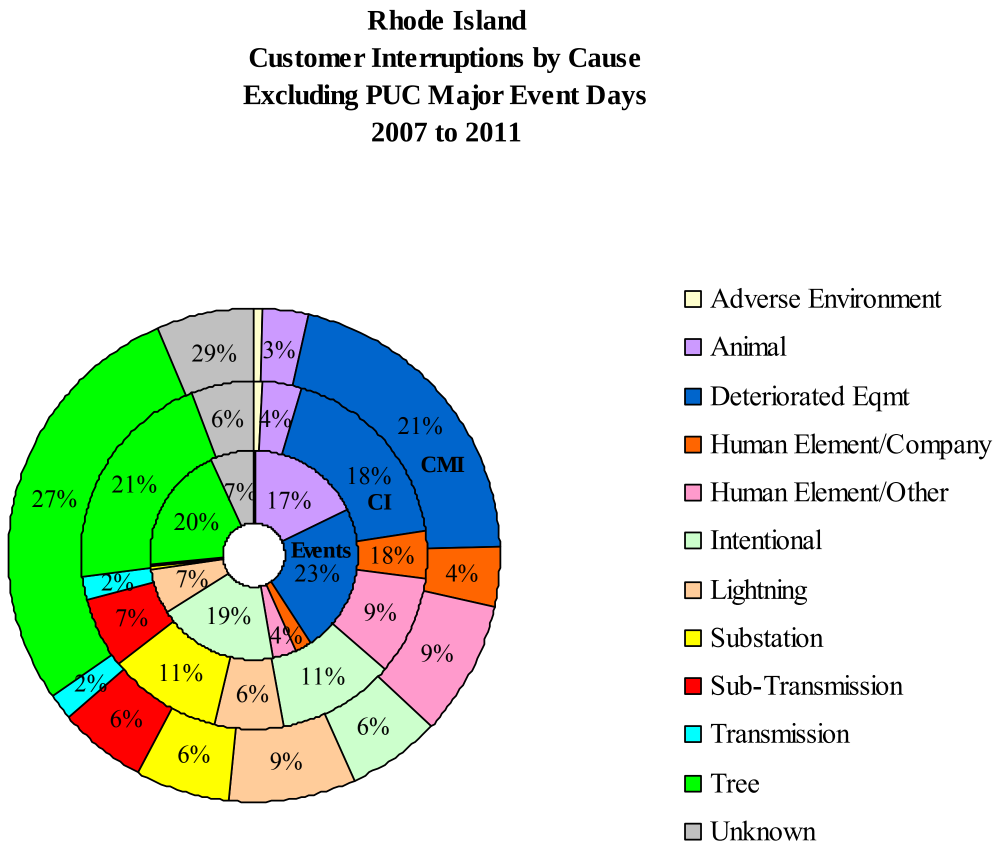
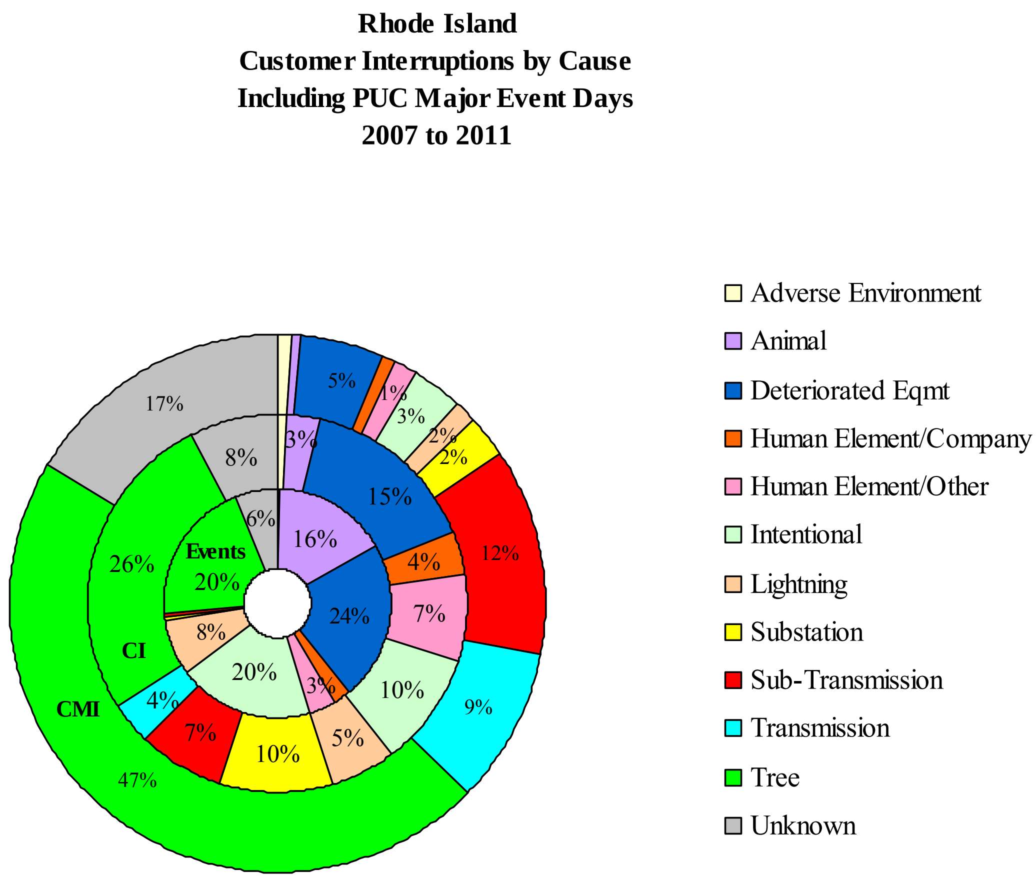


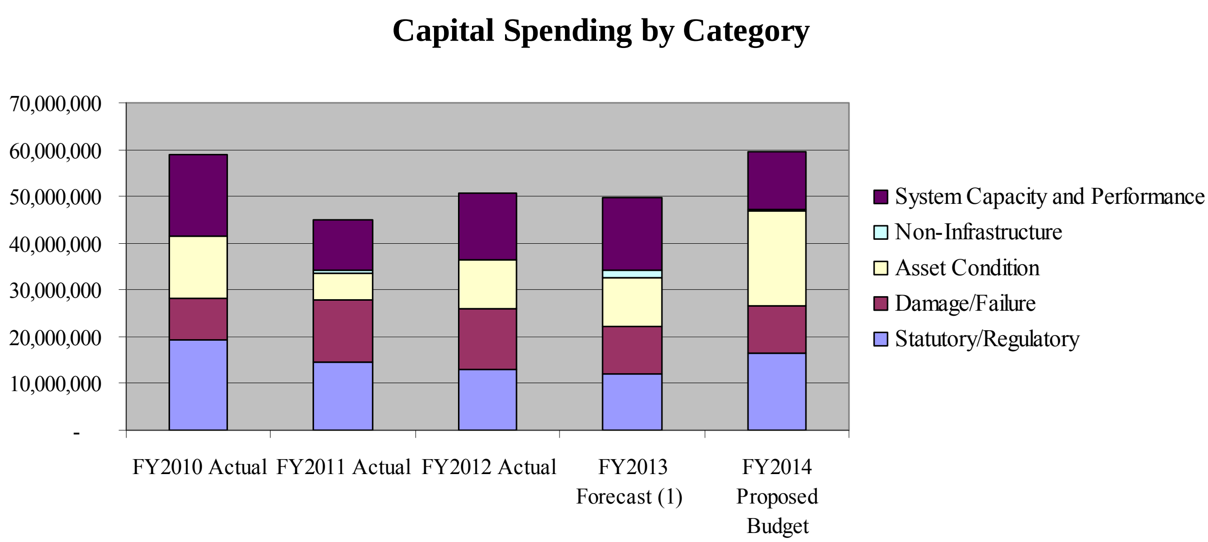
Chart 3: Customer Interruptions by Cause (including PUC Major Event Days)



It is, therefore, critical that the Company continue to invest in its infrastructure and Vegetation Management and Inspection and Maintenance programs to provide reliable electric delivery service to customers.

As shown in Chart 4, the Company plans to invest $59.6 million to maintain the safety and reliability of its electric delivery infrastructure in FY 2014, covering the period from April 2013 through March 2014. This spending level is 5 percent higher than the Company's proposed budget for capital improvements on the Rhode Island network during FY 2013.

Chart 4: Capital Spending by Key Driver Category



(1) This is the 2nd Quarter Electric ISR Plan forecast (as filed on November 30, 2012).

Because a portion of the proposed capital spending in FY 2014 is for projects (mainly substation projects) that will be completed over multiple years, the Company anticipates that only a portion of that spending will be placed into service in FY 2014. Likewise, a portion of the capital to be placed in service in FY 2014 will also reflect the capital spending for similar multiyear projects that commenced in prior years.

A. Summary of Investment Plan by Key Driver

Chart 5 below summarizes the planned spending level for each of the key driver categories of the Electric ISR Plan proposed for FY 2014.

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

SPENDING RATIONALE	**FY 2014 PROPOSED BUDGET**	**%**
Statutory/Regulatory	$16,509,000	28%
Damage/Failure	$10,050,000	17%
Subtotal	*$26,559,000*	*45%*
Asset Condition	$20,242,000	33%
Non-Infrastructure	$255,000	1%
System Capacity and Performance	$12,544,000	21%
Subtotal	*$33,041,000*	*55%*
Grand Total	**$59,600,000**	100%

As shown in Chart 5, twenty-eight percent of the spending for capital projects in FY 2014 is necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements, or mandates. Such investments arise from the Company's regulatory, governmental, or contractual obligations, such as responding to new customer service requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by cities and towns as well as the Rhode Island Department of Transportation ("RIDOT"). For the most part, the scope and timing of this work is defined by others external to the Company. These projects will account for approximately $16.5 million, or 28 percent, of the proposed capital budget in FY 2014.

The need to immediately repair failed and damaged equipment equates to approximately $10.1 million, or 17 percent, of the Company's investment. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes.

The Company considers the investment required to comply with statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and "non-discretionary" in terms of scope and timing. Together, these items amount to approximately $26.6 million, or 45 percent, of proposed capital investment in FY 2014.

The Company also has minimal discretion to address load constraints caused by the existing and growing and/or shifting demands of customers. Investments to address these issues account for 83 percent of the investment dollars categorized as system capacity and performance, or 18 percent of the proposed capital budget in FY 2014. These investments are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting demands of customers and to maintain the requisite power quality required by customers. Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the Company's system and capacity loading policy and are designed to reduce degradation of equipment's service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

The Company has somewhat more discretion with regard to the timing of the other categories and closely monitors the risk associated with delaying such projects due to the potential impact of the consequences of the failure of equipment or systems. The reliability, asset condition, and non-infrastructure projects that the Company will pursue in FY 2014 have been chosen to minimize the likelihood of reliability issues and other problems due to underinvestment in the overall system.

Investments that are required to maintain reliable service to customers accounted for 17 percent of the system capacity and performance category or three percent of the total FY 2014 capital budget. This category includes investment to improve the overall performance of the network. These reliability enhancements include the expansion of the Company's remote monitoring and control capability, a project to storm harden an area that has experienced multiple interruptions and smaller localized enhancements identified by our field operations personnel. Together with load relief projects, these performance projects amount to approximately $12.5 million, or 21 percent, of network investment.

Projects necessary based on the condition of the infrastructure assets account for $20.2 million, or 33 percent, of the proposed capital spending in FY 2014. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the potential for reliability issues. Moreover, the large number of aged assets in the Company's service area requires the Company to develop strategies to replace assets if their condition impairs reliable, safe service to customers. Experience with assets that have poor operating characteristics in the field has led the Company to develop strategies to remove such equipment. These strategies are developed to avoid the possibility that a large number of similar assets will fail at the same time or within short windows of time. The investments made in these assets are prioritized based on their probability of failure along with consequences of such an event.

The "non-infrastructure" category of investment is for those capital expenditures that do not fit into one of the aforementioned categories but which are necessary to run the electric system, such as general and telecommunications equipment. In total, capital spending for non-infrastructure projects will account for $255,000 and less than one percent of capital spending in FY 2014.

B. Development of the Annual Capital Plan

Each year, the Company develops an Annual Work Plan designed to achieve its overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. At the outset, the Annual Work Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by spending category: Statutory/Regulatory, Damage/Failure, System Capacity and Performance, and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects.

To optimize the plan budget and resources, a risk score is assigned to each project. The project risk score is generated by a project decision support matrix that assigns a project risk score based upon the estimated probability and consequence of a particular system event occurring, including the impact on customers and the public. The project risk score takes into account key performance areas such as safety, reliability, and environmental, while also accounting for criticality. Historical and forward looking checks are made by spending rationale to identify any deviations from expected or historical trends.

Once the mandatory budget level has been established, programs and projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) are reviewed for inclusion in the spending plan. Plan inclusion/exclusion for any given project is based on several different factors, including, but not limited to: project new or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the total cost and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project.

The portfolio, along with supporting risk analyses, is presented to the Company's senior executives, approved by the Jurisdictional President for Rhode Island, and ultimately goes to the Board as part of the entire United States plan for review and approval. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible to manage to the approved budget.

The capital plan for FY 2014 presented herein represents the Company's best information regarding the investments it will need to make to sustain the safe, reliable and efficient operation of the electric system. As described above, some of the projects are already in progress or soon to be in progress. Estimates for those projects are quite refined. Other projects are at earlier stages in the project evolution process. The budgets for those projects are accordingly less refined, and are more susceptible to change. The plan is continuously reviewed during the year, for changes in assumptions, constraints, project delays, accelerations, outage coordination, permitting/licensing/agency approvals, system operations, performance, safety, and customer driven needs that arise. The plan is updated accordingly throughout the current year.

As stated above, the result of the budgeting process is the approval of a total dollar amount for capital spending in the budget year. In addition to this planning and budgeting process, specific approval must be obtained for any strategy, program, or project within the Annual Work Plan. Approval is obtained through a "Delegation of Authority" ("DOA") requirement prior to proceeding with project work, including engineering and construction. Each project must receive the appropriate level of management authorization via a Project Sanction Paper ("PSP") prior to the start of any work. Approval authority is administered in accordance with the Company's DOA governance policy.

To obtain approval, the project sponsor must develop a detailed PSP relevant to the decision process including:

- Project background, description and drivers
- Business issues and the analysis of alternative courses of action
- Cost analysis of the proposed project
- Project schedule, milestones, and implementation plan

Once an approved project is completed, the project manager is responsible for preparing closure papers, which present information on a number of factors including a discussion of whether and to what extent project deliverables were achieved and lessons learned as a result of project implementation.

Capital projects are authorized for construction following preliminary engineering. Reauthorization is required if the project cost is expected to exceed the approved estimate plus an approved variance range identified in the project spending plan. Any reauthorization request must include original authorized amount, the variance amount, the reasons for the variance and the details and costs of the variance drivers, as well as the estimated impact on the current year's spending. Project spending is monitored monthly against authorized levels by the project management and program management groups. Exception reports covering actual or forecasted project spending greater than authorized amounts are reviewed monthly. The Company includes certain reserve line items in its spending plan, by budget category, to allocate funds for projects whose scope and timing have not yet been determined. In such cases, historical trends are used to develop the appropriate reserve levels. As the specific project details become available, inevitable "emergent" projects are added to the plan with funding drawn from the reserve funds. The majority of projects that are emergent are the result of in-year occurrences in mandatory, or "non-discretionary", project categories such as damaged or failed equipment, customer or generator requirements, or regulatory mandates. Reserve funds are also established for high priority risk score projects that may arise during the current year in response to unforeseen system reliability or loading concerns. The Company tracks and manages budgetary reserves and emergent projects as part of its investment planning and current year spending management processes.

C. Description of Large Programs and Projects

Attachment 1 to this section provides program and project detail on major projects that supports the proposed level of capital spending by key driver shown on Chart 5. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available at the present time and the risk score associated with the project.

i. Statutory/Regulatory

As shown in Attachment 1, the Company has set a budget of $16.5 million to meet its Statutory/Regulatory requirements in FY 2014. This is 17 percent lower than the FY 2013 budget of $20.0 million.

Approximately 44 percent of the Statutory/Regulatory budget is required to establish electric delivery service to new customers. The Company currently expects to spend approximately $7.3 million for this category in FY 2014. It is important to note that the actual and proposed spending in this category is net of contributions in aid of construction that are received from customers.

Included in this category is the Shun Pike project, which is a statutory project driven by a large industrial customer request. This project consists of two project phases. This initial phase includes the installation of a new 115kV/13.2kV substation. The 13.2kV equipment will be dedicated to serve the customer load, while portions of the transmission work will be shared across the two project phases.[8] The proposed project spend in FY2014 is $0.65 million.

[8] Phase 2 is a system capacity and reliability project driven by load relief. The proposed scope for Phase 2 will require the installation of 2-115kV/12.47kV transformers with eight feeders for the purpose of distribution load relief in the surrounding areas.

Required spending for public projects is expected to remain consistent with recent spending levels. These categories include such projects as:

- Relocating/adding company assets due to road or bridge-work
- Moving assets such as poles to accommodate a new driveway or other similar customer requests
- Construction as requested by the telephone company, public authorities, towns, municipalities, RIDOT, and other similar entities
- Required environmental expenditures

The budget for FY 2014 includes $0.82 million for manhole and duct infrastructure installation in coordination with RIDOT construction of new roads in the vicinity of the I-195 relocation. The schedule for this work is determined by the RIDOT.

Because much of this construction work is variable and requested on short notice, the Company must set a budget based on previous experience since it does not yet have the project detail. Since the Company gets reimbursed for a portion of this spending (especially for work requested by the RIDOT), the budget placeholder represents the capital expected to be spent, net of reimbursements.

The Company expects that it will need to spend at approximately the same level as in recent years to facilitate third-party attachments. Spending to enable third-party attachments is highly variable year-to-year based on the timing of contributions from third parties and the cost to make sure that the Company's assets meet the standards required to enable the attachments.

The latter is not reimbursed by third party customers and as such may increase the balance spent within this category.

ii. Damage/Failure

The Company is proposing a $10.1 million budget for FY 2014 for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. This is approximately four percent less than the $10.4 million budget for FY 2013 but comparable to the average level of spending for this purpose during the FY 2009 to FY 2012 period. Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historic trends. A portion of the damage/failure budget allows for larger project work that will arise within the current year as well as carryover projects from the prior fiscal year where the final restoration of the plant in-service will not be complete until FY 2014 (e.g. failed substation transformer). The budget set for FY 2014 also includes capital spending to address issues that have been identified for immediate repair as part of the inspection and maintenance program as described in Section 4.

The damage/failure portion of the Company's capital plan has three major components:

- Damage/Failure Blanket Projects – For relatively small failures within substation or line or those whose size is unknown at the time of the failure. The budget for FY 2014 is built on the assumption of flat failure rates along with inflation assumptions.
- Damage/Failure Reserve for Specific Projects – A reserve to address larger failures that require capital expenditures in excess of $100,000. The reserve is built on recent historic trends of such items and allows the

Company to complete unplanned work without having to halt work on projects that are planned to stay on target with the overall capital budget.

- Major Storms – Each year the Company carries a budgeted project for major storm activity that affects the Company's assets. While the actual spend in this category may vary greatly, this reserve, based on average trends over the past several years, allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required.

iii. Asset Condition

The Company is proposing to spend $20.2 million in FY 2014 to replace assets that must be replaced to maintain reliability performance. This level is 70 percent greater than the FY 2013 budget of $11.9 million. A portion of this increase reflects a shift in spending from the feeder hardening program, which is accounted for in the System Capacity & Performance spending rationale to the more systematic Inspection & Maintenance program which is accounted for in the Asset Condition spending rationale. In addition, the level of Inspection and Maintenance is increasing as compared to FY 2013, and is discussed in detail in Section 4. Another driver for the additional funding as compared to FY 2013 is an increase in the proposed spending for URD cable replacement, as discussed below.

URD Cable Strategy - This strategy applies to Underground Residential Development (URD) and Underground Commercial Development (UCD) cables sized #2 and 1/0 and does not apply to mainline or supply cables. It sets forth the approach for replacing or rehabilitating (through cable injection) these cables. This strategy supports the current method for handling cable failures by fixing immediately upon failure and offers options for managing cables that have sustained multiple failures. Although, interruptions on #2 and 1/0 cables do not significantly influence Company level service quality metrics, they can have significant localized impacts on affected neighborhoods. For URDs with at least three cable failures within the last three years, two options are considered for addressing repeated failures: cable rehabilitation through insulation injection or cable replacement. Insulation injection is identified as the preferred solution for direct buried Cross Linked Polyethylene (XLPE) cables in a loop fed arrangement. The overall condition of the primary and neutral cables and installation specifics will determine if insulation injection is a viable option. The Company proposes to spend $1.90 million to implement this strategy in FY 2014.

Underground Cable Strategy - The goal of this strategy is to replace primary underground cable that is in poor condition or has a poor operating history. The Company's present underground cable replacement program is a mixture of reactive "fix on fail" replacement in the Damage/Failure spending rationale and proactive replacement in the Asset Condition spending rationale based on type of construction, asset condition, and failure history for a specific asset and similar assets. Reactive "fix on failure" replacement, which the Company considers mandatory spending, often evolves into proactive replacement of an entire circuit or a localized portion of a circuit, which is considered discretionary spending. Discretionary spending for proactive replacement can be further categorized by that work justified by the need to eliminate repeated in-service failures, work justified by anticipated end-of-life based on historic performance or industry experience, and work made necessary by other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. Examples of distribution cables currently being planned for replacement include the 1168, 1103, 1109 A&B, and 1113 cables.

Strategy to Replace Distribution Substation Batteries - The Company has more than 80 battery systems in its distribution substations and these systems play a significant role in the safe and reliable operation of substations. The batteries and chargers in these systems provide DC power for protection, control, and communications within the substation and between substations and control centers. One goal of the Company's strategy is to replace batteries that are 20 years old or older. Another goal of the strategy is to ensure that battery systems meet the current operating requirements and perform their designed function. The Company proposes to spend $0.43 million in FY 2014 to implement this strategy.

The Substation Metalclad Switchgear Replacement Strategy and Program - This program is another important strategy to improve the reliability of substations. This strategy replaces switchgear that have known operating issues or are of the same type and manufacturer as equipment that has failed at another location. Presently there are 46 metalclad switchgear in Rhode Island operating between 4kV and 23kV. Of the 46 units, 36 units were installed prior to 1979. Several design factors with older vintage metalclad substations contribute to bus failures or component failures.

These factors include:

- Moisture Sealing Systems - Moisture and water contribute to most of the failures of metalclad switchgear, substations, and busses. Gaskets and caulking of enclosures deteriorate over time allowing rain and melting snow to enter.

- Ventilation - Metalclad interiors can reach high temperatures in the summer even if ventilation systems are working correctly. High temperatures degrade the lubrication in breaker mechanisms and other moving parts and can cause failure of electronic controls and relays.
- Insulation - Voids in insulation, which eventually lead to failure of the insulation when stressed at high voltages, are apparent in earlier vintage switchgear.

The distribution strategy is funded at $0.35 million in FY 2014 to perform the preliminary engineering work at the Lee Street substation with construction beginning in FY 2015.

The Substation Circuit Breaker Strategy and Program - This program targets obsolete and unreliable breaker families. The Company has approximately 836 distribution substation circuit breakers and reclosers in substations that it maintains, refurbishes, and replaces as necessary. Units with obsolete technology, such as air magnetic interruption, have been specifically identified for replacement. Additionally, where cost effective and where their conditions warrant, the Company bundles work and replaces disconnects, control cable, and other equipment associated with these circuit breakers. The Company proposes to spend approximately $1.05 million to implement this strategy in FY 2014. Targeted substations for breaker replacements include: Lincoln Avenue 72, Davisville 84, Bristol 51, Clarkson St. 31, Jepson, Putnam Pike 38, and Warren 5.

Replacement RTU Program – Substations - For FY 2014, the Replacement RTU Program has been incorporated into the Substation EMS/RTU (SCADA) Additions Program described below in the System Capacity and Performance section, which now considers asset condition based RTU replacement along with reliability based EMS expansion.

The Relay Replacement Strategy - This strategy intends to replace those relays, relay packages, communication packages and control houses that have operational issues or are obsolete and no longer supported by the manufacturer. A certain percentage of the electro-mechanical and solid state relay population is currently demonstrating a trend of decreasing reliability. The attempt to keep these relays in working order is thwarted by a lack of spare parts and knowledge base due to obsolescence. The primary intent of the strategy is to replace those relays that have a higher probability of failure.

The protection afforded by relays is critical to safety and the stability of the electric system. The relays are designed to protect high-value system assets from effects of system faults and to quickly isolate system disturbances so that no additional damage can occur, while ensuring continued safe and reliable operation of the system.

The strategy represents a six-year plan to replace transformer and under frequency relays that have been identified using the criteria mentioned above. The Company proposes to spend $0.85 million to implement this strategy in FY 2014.

Spare Substation Transformer Program - This program includes a substation transformer risk assessment and makes recommendations on necessary additions to transformer spares. Three spare transformers are planned for purchase in FY 2014. The first is a 34.5 kV to 11 kV transformer spare, which is required for a critical downtown area including medical facilities. Because of the arrangement of the electric system in this downtown area, this transformer requires a special winding configuration (delta zigzag). The second spare planned for purchase is a 22kV to 11kV transformer that will provide coverage for two of the Company's indoor substations. These transformers are presently being watched due to asset condition issues but have not been scheduled for replacement. The third spare transformer is a small grounding bank. Grounding banks are used at substations to provide improved protection schemes; however, loss of a grounding bank can result in loss of station protection until replaced. There are presently no available spares in the Company's inventory for any of the three cases described above. The Company proposes to spend $0.73 million to implement this program in FY 2014.

Eldred Substation Rebuild - This project is required to address asset condition and safety concerns at Eldred substation. This station is one of two 23/4kV stations that supply the island of Jamestown, Rhode Island. Eldred substation supplies the northern half of the island and Clarke Street substation supplies the southern half. Combined, these two stations supply approximately 3,120 customers with a peak demand of 10MW. A condition assessment of Eldred substation assets was performed and identified a need to replace three circuit breakers, the station power transformer, an air-break switch, voltage regulators, station fence, and retaining walls. The assessment also identified clearance concerns with the voltage regulators, station breakers, and the PT sensing transformers, which should be addressed utilizing an alternate station design.

The recommended plan is to install two modular feeders at Eldred substation. Each modular feeder will consist of a 23/4.16kV, 3.75/4.68 MVA transformer, 800A recloser, and 3-167kVA regulators. Additionally, new feeder getaways will be installed and the area distribution will be modified to consolidate three feeder positions into two feeder positions. This project will address asset condition, safety clearance issues, operational concerns, and supports the following strategies:

- Distribution Substation Circuit Breaker & Recloser Strategy
- Disconnects and Motor Operated Disconnects Strategy
- Voltage Regulator Strategy
- Distribution Substation Transformer Strategy

The project proposes to spend $1.18 million in FY 2014.

Network Arc Flash Program - This program addresses the requirements of the National Electrical Safety Code's ("NESC") Part 4: Work Rules for the Operation of Electric Supply and Communication Lines and Equipment. A 2012 revision to this part of the NESC requires an arc flash hazard analysis for work assignments on facilities operating under 1000 volts. The Company completed its analysis and determined issues concerning certain maintenance activities on its 480V spot network systems. This strategy will mitigate the calculated incident energy levels by installing engineering controls such as primary and secondary switches. The Company expects to address all of its 480V spot networks over a five year horizon. The project proposes to spend $0.25 million in FY 2014.

Flood Mitigation Projects - As discussed in the FY 2013 Electric ISR Plan, major river flooding occurred on the Pawtuxet River, Pawcatuck River, Blackstone River, and Hunt River from March 30 through April 1, 2010, which resulted in substations located in those areas being de-energized because of excessive water levels. The impacted areas represented a significant health and safety risk to personnel, reliability impacts to customers, as well as significant damage to mechanical, electrical, control, and communications equipment in these substations and their control houses.

On June 29, 2012, the Company filed its Rhode Island Flood Mitigation Plan[9] with the Commission. Following this filing, the Company has changed its recommended plan for two substations as a result of revised economics. First, the flood mitigation work for the Sockanossett substation will be deferred pending an area capacity study that may affect the need for this substation. To clarify further, the flood risk related work at the Sockanossett substation will be delayed by at least one year and may ultimately be eliminated. The second change is a result of refined estimates that were obtained for an option to elevate equipment at the Warwick Mall substation. This option is currently under review for feasibility, and a final plan at the Warwick Mall has not yet been determined.

Plans for FY 2014 include continuation of substation engineering, procurement of equipment, permitting and licensing, and the start of construction on several projects to address flood mitigation. The majority of these projects are multi-year projects. Projects in the FY 2014 budget are shown in the following table.

[9] Rhode Island Flood Mitigation Plan, Docket No. 4307.

Substation with Flood Risk	Preferred Alternative Substation	FY 2014 Activities	Projected Capital Spend FY 2014 ($M)
Sockanosett	to be determined	Engineering Study	$0.05
Westerly	Chase Hill (Hopkinton), Langworthy	Engineering, Procurement and Construction	$4.37
Pawtuxet	Lakewood, Point Street	Engineering and Construction	$0.45
Pontiac	Pontiac	Engineering and Procurement	$0.37
Warwick Mall	Warwick Mall	Engineering and Procurement	$0.20
Hunt River	Kent County	None	$0.00
Hope	Hope	Engineering and Procurement	$0.10
Riverside	Riverside	Engineering	$0.02
TOTAL			$5.56

The majority of the costs in the table above are associated with the Chase Hill (formerly Hopkinton) / Langworthy projects. As reported in previous filings, there were two phases to the Chase Hill / Langworthy work. Phase 1 was a Load Relief based project and phase 2 was flood risk mitigation work. The Company has combined these phases for project management and construction efficiencies. As a result, the numbers above are the total costs for both phases and not solely flood risk related dollars. In this filing and future filings the total costs associated with this project will be reflected in the System Capacity and Performance category.

Another noteworthy item in the table above is the inclusion of the Hunt River flood risk solution in the proposed Kent County Load Relief project. As described in the June 29, 2012, Rhode Island Flood Mitigation Plan, this option results in no proposed FY 2014 spend for Hunt River, but provides the most economic solution. The Kent County project is described in the System Capacity and Performance section below.

Inspection & Maintenance (I&M) Program - This program has both capital and O&M components. The proposed capital spending for FY 2014 of $8.5 million represents a significant increase in spending when compared to recent spending on the Feeder Hardening program, and is based on inspection results to date. Section 4 further discusses both the capital and O&M components of the I&M Program.

iv. System Capacity and Performance

The Company has set a budget of $12.5 million for system capacity and performance projects in FY 2014. This is a ten percent decrease from the $13.9 million that the Company budgeted in FY 2013. The System Capacity and Performance category is comprised of Load Relief and Reliability projects. The Load Relief projects account for $10.4 million, or 83 percent, of the proposed System Capacity and Performance spending in FY 2014.

These Load Relief projects were identified as part of the Company's annual capacity planning process which is conducted each year to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur. The capacity planning process includes the following tasks:

- Review of historic loading on each sub-transmission line, substation transformer, and distribution feeder;
- Weather adjustment of recent actual peak loads;
- Econometric forecast of future peak demand growth;
- Analysis of forecasted peak loads vis-à-vis equipment ratings;
- Consideration of system flexibility in response to various contingency scenarios; and
- Development of system enhancement project proposals.

The Company has developed a multi-step top down/bottom up process to forecast the loading on these assets to identify the need for capacity expansion projects. First, the Company uses an econometric model to forecast summer and winter peak loads in four power supply areas ("PSAs") in Rhode Island. The explanatory variables in this model include historical and forecasted economic conditions at the county level[10], historical peak load data for each PSA, and a forecast of weather conditions based on historical data from several weather stations.

The Company uses this model to simulate the historical and forecasted peak demand for each PSA under a normal and extreme weather scenario. The normal weather scenario assumes the same normal peak-producing weather for each year of the forecast. The extreme weather scenario assumes an upper bound peak demand for each PSA under a given set of economic conditions. Based on the historical experience, there is only a five percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

[10] This data and forecasts are provided by Moody's Economy.com.

The forecast of peak load for each PSA generated with the model incorporates the energy efficiency ("EE") savings achieved through 2011 since these savings would be reflected in the historical data used by the model. The Company subtracts forecasted incremental EE savings beyond the amounts achieved through 2011 from the load forecast for each PSA. The incremental system-wide EE savings is apportioned to each PSA based on its proportion of total system-wide load.

The PSA growth rates are applied to each of the substations and feeders within the area. Distribution planners then adjust forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planners use the forecasted peak loads for each feeder/substation under the extreme weather scenario to perform planning studies and to determine if the thermal capacity of its facilities is adequate.

Individual project proposals are identified to address planning criteria violations. At a conceptual level, these project proposals are prioritized and submitted for inclusion in future capital work plans. Projects in the load relief program are typically new or upgraded substations and distribution feeder mainline circuits. Other projects in this program are designed to improve the switching flexibility of the network, improve voltage profile, or to release capacity via improved reactive power support.

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. The goal is to seek the combination of wires and non-wires alternatives that solves capacity deficiencies in a cost effective manner that also considers the potential benefits and risks. As part of this process, the Company would conduct analysis at a level of detail commensurate with the scale of the problems and the cost of potential solutions. The Company proposed a pilot non-wires alternative project to the Commission on November 1, 2011, designed to test the capabilities of targeted energy efficiency applications to defer distribution investment.[11]

Some of the most significant Load Relief Projects for FY 2014 include:

- **Proposed New London Avenue Substation (formerly West Warwick Substation) -** Construction of a new 115kV/12.47kV substation in the City of Warwick to provide thermal relief to area distribution feeders, transformers, and supply lines and support projected growth in the area. A number of distribution circuits, transformers, and supply lines are projected above their normal and emergency ratings in the City of Warwick and Towns of West Warwick, Scituate, and West Greenwich. Land has been acquired to house this substation and the substation is in the process of being permitted.
- **Proposed Chase Hill Substation (formerly Hopkinton Substation) -** Construction of a new 115kV/12.47kV substation in the Town of Hopkinton to provide thermal relief to area distribution feeders, transformers, and supply lines and support projected growth in the area. A number of distribution circuits, transformers, and supply lines are projected above their normal and emergency ratings. This project will

[11] Docket No. 4296 - The Narragansett Electric Company, d/b/a National Grid 2012 System Reliability Procurement Plan.

also support retirement of the Ashaway substation. Land has been acquired to house this substation and the substation is in the process of being permitted. As described in the Flood Mitigation Projects part of the Asset Condition section, the Westerly substation flood risk solution is now included in this load relief project.

- **Proposed Newport Substation** - Construction of a new 69kV/13.8kV substation and all related distribution line work to develop five new 13.8kV feeders to provide load relief to the City of Newport. The completion of this project will provide thermal relief to overloaded feeders and supply lines in the City of Newport and improve the overall reliability to Aquidneck Island. The installation of new 13.8kV feeders and conversion of 4kV load to the new station improves the reliability of the 23kV supply and 13.8kV distribution systems during contingencies. This plan supports the retirement of Bailey Brook and Vernon substations to address reliability, asset condition and environmental concerns with the most economical solution.
- **Johnston Substation 12.47kV Substation Expansion** - This project will expand a newer 12.47kV bus section and upgrade the 40MVA #3 Transformer to a 55MVA unit. This project will address capacity issues with four heavily loaded feeders west of the station, asset condition issues in the old 12.47kV switchyard, and loss of supply cables in the older 12.47kV switchyard as a result of the failure of a three-winding

transformer in the spring of 2009 (which resulted in a loss of one of two 12.47kV supply lines in the older half of the station). Temporary cables presently tie the new 12.47kV bus to the old 12.47kV bus sections, increasing customer exposure.

- **Kilvert Street – Install Second Transformer and Two-New Feeders** – This project is required to mitigate load at risk in the cities of Cranston and Warwick for loss of the Kilvert Street substation transformer and to provide thermal relief to area distribution feeders, transformers, and supply lines. Kilvert Street substation has a single 115kV/13.2kV, 33/44/55MVA transformer supplying four distribution feeders. Loss of the Kilvert Street transformer results in an initial outage of 29 MW of load. Approximately 14 MW of load can be transferred to other area substations through feeder ties leaving 15 MW of load un-served until a spare or mobile transformer is installed. This results in an exposure of 400MWh.
- **Kent County – Install Second Transformer and One-New Feeder:** This project is required to mitigate load at risk for loss of the Kent County substation transformer and to address flooding and environmental risks that currently exist at Hunt River substation. Kent County substation has a single transformer supplying four distribution feeders. It supplies approximately 9,400 customers with a peak load is 42MW. Upon contingency approximately 27MW of load (or approximately 6,000

customers) would be un-served until a spare or mobile transformer is installed resulting in an exposure of 696MWh. To address flood issues at Hunt River substation, this project installs a new feeder at Kent County substation. Hunt River substation is located in the flood plain adjacent to the Hunt River and is located within a wellhead protection area that supplies drinking water to the Towns of East Greenwich and North Kingstown and the City of Warwick. The additional feeder at Kent County provides capacity to retire Hunt River, addressing the flood issues in a cost-effective manner when compared to station reconstruction.

- **Highland Drive Substation** – This project includes the construction of a new 115kV/13.8kV low profile substation, six 13.8kV distribution feeders, and all related distribution line work in Cumberland, Rhode Island. This project is designed to provide contingency relief at Riverside substation and Staples substation, relieving the Riverside 108W55 and Staples 112W43 and 112W41 feeders due to spot load at the CVS Park. This project replaced the Staples substation project for the addition of a 13.8kV circuit breaker.

In addition to these projects, the Company also has a Distribution Line Transformer Strategy to mitigate unplanned outage/failure risks due to overloads and asset condition of distribution line transformers. There are approximately 64,000 distribution transformers on the Company's distribution system. Transformer loading is reviewed annually using reports generated by the Company's Geographical Information System ("GIS"). Transformers with calculated demands exceeding load limits specified in the applicable construction standard are investigated, and overloaded installations are addressed by replacement with larger units or load is relieved via installation of a second transformer. The physical condition of distribution line transformers is evaluated on a five-year cycle as part of the Inspection and Maintenance Strategy. Poor condition units are replaced based on inspection results. The strategy is in addition to replacements that are performed during customer-service upgrades, public requirements projects, and system-improvement projects. The main benefit of this strategy is the maximization of asset utilization and sustained reliability performance. The Distribution Line Transformer strategy is funded at $1.8 million in FY 2014.

The Company also has a Distribution Load Relief Blanket to provide the necessary funding for other load relief projects. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The amount of funding in the blanket project is reviewed and approved each year based on the results of the previous annual capacity planning review, historical trends in the volume of work required, as well as a forecasted impact of inflation on material and labor rates. The current year spending in the project is monitored on a monthly basis. The blankets also provide local field engineering with the control accounts to facilitate timely resolution of system and equipment loading issues. These blanket projects are utilized to respond to issues such as overloaded sections of wire/cable or step-down transformers, the installation of feeder voltage regulators and capacitors, and minor work necessary to facilitate the reallocation of load on existing circuits. These blanket projects are budgeted at $0.24 million in FY 2014.

In addition to the Load Relief Projects identified above, the Company is also proposing to spend approximately $2.1 million in FY 2014 on several programs designed to maintain system reliability, which is 64 percent less than the Company's spending level of $5.8 million for these programs from FY 2013. This decrease in spending is driven by the essential completion of the feeder hardening, recloser and cutout replacement strategies, as described below.

Feeder Hardening Strategy - The Feeder Hardening strategy identified feeders with characteristics indicating the potential for significant reliability performance improvements related to deteriorated overhead equipment and/or lightning interruptions. This program was essentially completed in FY 2013. The FY 2014 funding for feeder hardening is to complete work on poles remaining to be set by Verizon in their maintenance areas. The Feeder Hardening strategy is funded at approximately $0.2 million in FY 2014. Going forward, the Inspection & Maintenance program replaces feeder hardening as discussed in Section 4.

Distribution Line Recloser Installation - The recloser application strategy was a reliability-focused strategy to install line reclosers on overhead distribution lines. This program was completed in FY 2013. The Distribution Line Recloser Strategy is not funded in FY 2014. Any individual reclosers which are required will be justified on a stand alone basis for reliability or protection needs and installed under the reliability blanket or a specific project for such things as new feeders.

Potted Porcelain Cutout Replacement - This strategy is a reliability-focused strategy to eliminate potted porcelain cutouts to reduce potential safety hazards for employees and increase reliability as measured by SAIDI/SAIFI. Fuse cutouts provide over-current protection for the electric distribution system; however, potted porcelain cutouts experience a high rate of failures.

National Grid installed porcelain cutouts throughout its service area in the early to mid-1980s through early 2001, during which time potted porcelain cutouts were the style used most extensively in the utility industry. Beginning in 2006, National Grid adopted a policy of replacing all potted porcelain cutouts on the Company's system to respond to equipment failures and the associated safety risk posed by this equipment. The inspection and maintenance program incorporates the components of the potted porcelain cutout replacement strategy after FY 2013. Remaining costs in this Cutout Replacement strategy are related to existing work designed and currently in the Company's construction queue. The potted porcelain cutout strategy is funded at $0.3 million in FY 2014.

Distribution Reliability Blanket - In addition to specific projects (i.e. those $100,000 or greater), the Company also budgets for work less than $100,000 under a Distribution Reliability Blanket Project. The amount of funding in each divisional blanket project is reviewed and approved each year based on the results of the previous annual reliability review, historical trends in the volume of work required, as well as a forecasted impact of inflation on material and labor rates. The current year spending in each divisional project is monitored on a monthly basis. These projects are established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. The blankets also provide local field engineering in each operating division with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. These blanket projects are budgeted at $1.2 million in FY 2014.

Tunk Hill Reliability Project - This project includes reconductoring an area from bare conductor to tree wire in a spacer cable arrangement to improve customer reliability. This project is being scoped as a pilot in response to analysis completed as part of a review of the Company's Minor Storm Strategy to address pockets on the distribution system that have experienced multiple interruptions during minor storms over the past five years. The Company defines "Minor Storms" as occurring on days when the network experiences an exponentially greater number (between 1.5 and 2.5 Beta plus three times the average number of events) of SAIDI minutes due to a weather event. During the Minor Storms identified over the past five years, over 800 customers in the Tunk Hill Road, Scituate area experienced 4 or more outages. The Company proposes an approximately $1.0 million budget for this program in FY 2014.

Substation EMS/RTU (SCADA) Additions Program - The Company is proposing to expand the EMS/RTU program to improve reliability performance, increase operational effectiveness, and to provide data for asset expansion or operational studies. The Company proposes an approximately $1.0 million budget for this program in FY 2014. Targeted substations, subject to resource planning and other project constraints include: Elmwood, Lincoln Avenue 72, Natick 29, Hospital Substation 146, Hopkins Hill, Harrison 32, Davisville, North Aquidneck 21, and South Aquidneck 122.

Volt/Var Management Project - The Company is considering a project with a Rhode Island company, UtiliData, where the two companies could facilitate a project in Rhode Island for volt/var management. UtiliData is a control system integrator providing substation and distribution automation, SCADA, consulting, engineering, design, integration, control, automated energy conservation and energy management solutions to the electric utility industry.

Volt/Var management systems use centralized control algorithms to optimize the voltage use on the system. This may result in reduced losses on the system and more reliable performance of the system for customers. The Company believes that an analysis of the capabilities of this emerging technology to manage reactive resources and voltage regulating equipment on the distribution system is necessary.

The planning and engineering design process will include: the use of traditional system optimization techniques with feeder capacitors operating in a decentralized manner, the documentation of those projected benefits, the addition of a centralized control philosophy, and the recording of those additional benefits (projected). In parallel, a more detailed engineering and design cost will also be developed, and then a comparison can be made of the traditional decentralized approach against the centralized control philosophy. The Company will review the analysis and cost proposals with the Division, and implementation would commence in FY 2014 on an agreed upon plan. The Company is recommending $0.5 million for the project in FY 2014.

D. Recovery of Electric ISR Plan Capital Investment – Capital Placed In Service

In previous Electric ISR Plan filings, the Company calculated the revenue requirement based on the Company's projected capital amounts to be placed into service plus associated cost of removal. To develop its Capital Placed In-Service figure for this filing, the Company has used estimated timing of in-service dates for capital spending being placed into service during FY 2014. Each year, as part of the Company's annual reconciliation, the revenue requirement related to mandatory, or nondiscretionary in-service amounts, or that are attributable to the statutory/regulatory and damage failure categories, was trued up based on the lesser of actual non-discretionary spending or actual non-discretionary capital investments placed into service on a cumulative basis since the inception of the Electric ISR Plan in April 2011. The revenue requirement associated with all other capital investments was trued up based on the lesser of allowed discretionary capital spending or actual capital investment placed into service on a cumulative basis since the inception of the Electric ISR Plan in April 2011. Because of the multi-year nature of certain projects, current and prior year(s) capital spending was included in the plant in-service amount when a project is placed into service during the fiscal year. Similarly, the capital portion of a project included in a fiscal year's spending plan that will be placed into service in future fiscal periods was included in subsequent revenue requirement calculations during that project's in-service year.

Chart 6 below provides details as to total FY 2014 amounts for Capital Spending, Plant-Plant In-Service and Cost of Removal that have been used in the development of the FY 2014 Electric ISR Plan revenue requirement.

Chart 6: Proposed FY 2014 Capital Spending, Plant In Service, and Cost of Removal (COR)

SPENDING RATIONALE	PROPOSED CAPITAL SPENDING FY 2014	NEW CAPITAL PLACED IN SERVICE FY 2014	ESTIMATED COST OF REMOVAL	NEW CAPITAL IN SERVICE PLUS COR
Statutory/Regulatory	16,509,000	16,319,000	2,219,000	18,538,000
Damage/Failure	10,050,000	9,977,000	1,658,000	11,635,000
Subtotal	*26,559,000*	*26,296,000*	*3,877,000*	*30,173,000*
Non-Infrastructure	255,000	257,000	-	257,000
Asset Condition	20,242,000	17,954,000	4,606,000	22,560,000
System Capacity & Performance	12,544,000	8,866,000	1,062,000	9,928,000
Subtotal	*33,041,000*	*27,077,000*	*5,668,000*	*32,745,000*
Grand Total	59,600,000	53,373,000	9,545,000	62,918,000

Attachment 1 - Capital Spending by Key Driver Category and Budget Classification

SPENDING RATIONALE	BUDGET CLASSIFICATION	FY 2010 ACTUAL	FY 2011 ACTUAL	FY 2012 ACTUAL	FY 2013 FORECAST	FY 2014 BUDGET
Statutory/Regulatory	3rd Party Attachments	780,847	(909,712)	463,848		514,000
	Distributed Generation	-	-	-		162,000
	Land and Land Rights	274,560	281,215	185,520		190,000
	Meters - Dist	2,042,048	2,214,951	1,496,949		1,752,000
	New Business - Commercial	4,705,078	4,286,660	3,390,872		4,300,000
	New Business - Residential	3,256,239	3,529,650	2,833,259		3,025,000
	Outdoor Lighting - Capital	1,003,097	411,364	495,328		537,000
	Public Requirements	3,121,260	1,539,416	1,134,582		2,599,000
	Transformers & Related Equipment	4,128,756	3,277,796	3,074,796		3,430,000
Statutory/Regulatory Total		**19,311,885**	**14,631,340**	**13,075,154**	**11,999,000**	**16,509,000**
Damage/Failure	Damage/Failure	9,143,559	8,330,840	9,573,923		9,375,000
	Major Storms - Dist	(112,426)	4,863,261	3,418,936		675,000
Damage/Failure Total		**9,031,133**	**13,194,101**	**12,992,859**	**10,096,000**	**10,050,000**
Non-Infrastructure	General Equipment - Dist	391,872	60,548	148,707		105,000
	Corporate/Admin/General	(1,238,810)	645,055	117,838		-
	Telecommunications Capital - Dist	-	-	-		150,000
Non-Infrastructure Total		**(846,938)**	**705,603**	**266,545**	**1,589,000**	**255,000**
Asset Condition	Asset Replacement	12,574,361	5,604,107	9,766,995		11,377,000
	Asset Replacement - I&M (NE)	490,942	226,693	553,104		8,515,000
	Safety	-	-	-		350,000
Asset Condition Total		**13,065,303**	**5,830,800**	**10,320,099**	**10,462,000**	**20,242,000**
System Capacity & Performance	Load Relief	8,798,076	6,011,935	8,836,739		10,396,500
	Reliability	5,768,069	2,798,644	2,554,262		1,947,500
	Reliability - FEEDER HARDENING	2,888,145	1,984,135	2,564,239		200,000
System Capacity & Performance Total		**17,454,290**	**10,794,714**	**13,955,240**	**15,606,000**	**12,544,000**
Grand Total		**58,015,673**	**45,156,558**	**50,609,897**	**49,752,000**	**59,600,000**

Attachment 2 - Project Detail for Proposed FY 2014 Capital Spending

SPENDING RATIONALE	BUDGET CLASSIFICATION	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY 2014 PROPOSED BUDGET
Statutory/Regulatory	3rd Party Attachments	COS022	03538 Ocean St-Dist-3rd Party Attch Blnkt	49	514,000
	3rd Party Attachments Total				**514,000**
	Distributed Generation	CD1024	19247 Wind Energy Development – N. Kingstown Green, LLC	49	137,000
		PPM 19241	RI225 NBC Point St 76F8 DTT	49	25,000
	Distributed Generation Total				**162,000**
	Land and Land Rights	COS009	03542 Ocean St-Dist-Land/Rights Blanket	49	190,000
	Land and Land Rights Total				**190,000**
	Meters - Dist	CN4904	03489 Narragansett Meter Purchases	49	1,180,000
		COS004	03544 Ocean St-Dist-Meter Blanket	49	572,000
	Meters - Dist Total				**1,752,000**
	New Business - Commercial	CD0722	17064 New Shun Pike Substation - 23kV Line	49	150,000
		CD0723	17063 New Shun Pike Substation - 23kV Sub	49	500,000
		COS011	03545 Ocean St-Dist-New Bus-Comm Blanket	49	3,050,000
		PPM 9453	09453 City of Warwick Pump Station, Kristen Ct.	49	100,000
		RESERVE 049_011 LINE	03703 Reserve for New Business Commercial Unidentified Specifics & Schedule Changes - 49	49	500,000
	New Business - Commercial Total				**4,300,000**
	New Business - Residential	COS010	03546 Ocean St-Dist-New Bus-Resid Blanket	49	3,025,000
	New Business - Residential Total				**3,025,000**
	Outdoor Lighting - Capital	COS012	03549 Ocean St-Dist-St Light Blanket	49	537,000
	Outdoor Lighting - Capital Total				**537,000**
	Public Requirements	C08775	03139 DOTR-Conant St R/R Bridge Pawtucket	49	320,000
		C35087	03136 DOTR-Apponaug Circulator Imprv Warw	49	450,000
		C35764	04408 Goat Island Line Relocation	49	50,000
		C36683	09299 DOTR-Natick Bridge No. 383 Warw/WW	49	100,000
		CD0002	04473 Miriam Hospital Second Feeder Service	49	320,000
		CD0076	10817 DOTR-Atwells Avenue Bridge No. 975, Providence	49	30,000
		CD0135	04485 I-195 Contract 14 - Providence, RI	49	590,000
		CD0138	10867 West Farnum Station Offload Make-Ready	49	20,000
		CD0189	11411 DOTR-Central Bridge No. 182 Replacement, Barrington	49	160,000
		CD0766	04486 I-195 Contract 15 - Providence	49	225,000
		CD0996	19185 ACNW Vault 46 Structural Repairs, Providence	49	25,000
		CD0997	19186 ACNW Vault 34 Structural Repairs, Providence	49	25,000
		COS013	03547 Ocean St-Dist-Public Require Blankt	49	984,000
		RESERVE 049_013 LINE	03709 Reserve for Public Requirements Unidentified Specifics & Schedule Changes - 49	49	(700,000)
	Public Requirements Total				**2,599,000**
	Transformers & Related Equipment	CN4920	03491 Narragansett Transformer Purchases	49	3,430,000
	Transformers & Related Equipment Total				**3,430,000**
Statutory/Regulatory Total					**16,509,000**
Damage/Failure	Damage/Failure	C18593	03204 DxT Substation Dmg/Fail Reserve C49	49	300,000
		COS002	03550 Ocean St-Dist-Subs Blanket	49	644,000
		COS014	03540 Ocean St-Dist-Damage&Failure Blankt	49	7,531,000
		RESERVE 049_014 LINE	03698 Reserve for Damage/Failure Unidentified Specifics & Schedule Changes - 49	49	900,000
	Damage/Failure Total				**9,375,000**
	Major Storms - Dist	C22433	03608 OSD Storm Cap Program Project	49	675,000
	Major Storms - Dist Total				**675,000**
Damage/Failure Total					**10,050,000**
Non-Infrastructure	General Equipment - Dist	COS006	03541 Ocean St-Dist-Genl Equip Blanket	49	105,000
	General Equipment - Dist Total				**105,000**
	Telecommunications Capital - Dist	COS021	03551 Ocean St-Dist-Telecomm Blanket	49	150,000
	Telecommunications Capital - Dist Total				**150,000**
Non-Infrastructure Total					**255,000**

SPENDING RATIONALE	BUDGET CLASSIFICATION	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY 2014 PROPOSED BUDGET
Asset Condition	Asset Replacement	C06644	03389 IE - OS Targeted Pole Replace	40	200,000
		C20297	03740 Sac AB Repl Prog Phase 7 NEC DxT	49	150,000
		C23852	03409 Inst Ductline Governor St. Prov.	30	100,000
		C25803	03576 OS ARP Transformers	34	450,000
		C25815	03570 OS ARP Insul, SensDev, Surge Arrest	40	245,000
		C26058	03575 OS ARP Spare Substation Transformer	34	725,000
		C31400	03390 IE_OS URD Cable Replacement	36	1,500,000
		C31777	03586 OS IE UG Cable Repl Program - budget	40	1,000,000
		C32019	03062 Batts/Chargers NE South OS RI	40	250,000
		C32028	03672 Regulator Repl-NE South OS RI	28	90,000
		C32278	03567 OS ARP Breakers & Reclosers	40	1,050,000
		C32583	03571 OS ARP Metal Clad	39	350,000
		C33843	03061 BatteryRplStrategyCo49DxT	40	180,000
		C35586	04453 Relay Replacement Strategy Co 49DxT	47	850,000
		C36230	11969 Langworthy Substation (D Sub)	34	1,520,000
		C36232	11970 Langworthy Substation (D Line)	34	50,000
		C36417	09292 1168 Cable Replacement	34	80,000
		CD0641	17883 Retire Pawtuxet Substation (D-Line)	49	450,000
		CD0648	11696 Eldred Sub Asset Replacement (D-Sub)	36	1,080,000
		CD0659	11694 Eldred Sub Asset Replacement (D-Line)	36	100,000
		CD0937	18891 Village Green URD Rehab	36	400,000
		CD0998	19056 Replace switchgear - Huntington Towers, Providence	36	85,000
		CD1003	19057 Replace switchgear - Parkis Place, Providence	36	95,000
		COS017	03539 Ocean St-Dist-Asset Replace Blanket	49	1,205,000
		PPM 9802	09802 Sockanosset Substation - RI Flood Restoration	42	50,000
		PPM 19592	19592 Fdr 1113 - Install Cable Fountain St & various locns, Providence	30	100,000
		PPM 19597	19597 Fdr 1109A - Install Cable Dorrance St & north, Providence	30	50,000
		PPM 19600	19600 Fdr 1103 - Install Cable South Main St., Providence	30	25,000
		PPM 19596	19596 Fdr 1109B - Install Cable Pine St & west, Providence	30	450,000
		PPM 19601	19601 Capital Ctr Fdrs - Elim T-body joints, Providence	30	200,000
		PPM 19598	19598 Memorial Blvd Easton's Beach inst ductline & cable, Newport	30	800,000
		PPM 17337	17337 Pontiac Substation Flood Restoration (D-Sub)	42	330,000
		PPM 17347	17347 Hope Substation Flood Restoration	31	100,000
		PPM 17348	17348 Warwick Mall Substation Flood Restoration	31	200,000
		PPM 17349	17349 Riverside Substation - RI Flood Restoration	31	20,000
		PPM 18514	18514 Pontiac substation Flood Restoration (D-Line)	49	40,000
		PPM 19201	19201 RAPR Replacement - RI	39	170,000
		RESERVE 049_017 LINE	03694 Reserve for Asset Replacement Unidentified Specifics & Schedule Changes - 49	34	(2,763,000)
		RESERVE 049_017 SUB	03696 Reserve for Asset Replacement Unidentified Specifics & Schedule Changes (substation) - 49	34	(600,000)
	Asset Replacement Total				**11,377,000**
	Asset Replacement - I&M (NE)	C14326	03358 I&M - OS D-Line UG Work From Insp	40	50,000
		C26281	03357 I&M - OS D-Line OH Work From Insp	40	8,465,000
	Asset Replacement - I&M (NE) Total				**8,515,000**
	Safety	PPM 18061	18061 Substation Integration Mitigation and HMI Replacement- OS	37	100,000
		PPM 18423	18423 Distribution Secondary Network Arc Flash	46	250,000
	Safety Total				**350,000**
Asset Condition Total					**20,242,000**

SPENDING RATIONALE	BUDGET CLASSIFICATION	PROJECT #	PROJECT DESCRIPTION	RISK SCORE	FY 2014 PROPOSED BUDGET
System Capacity & Performance	Load Relief	C05505	03383 IE - OS Dist Transformer Upgrades	40	1,800,000
		C13967	03643 PS&I Activity - Rhode Island	40	125,000
		C15158	03529 Newport Substation (D-Sub)	41	400,000
		C24159	03531 Newport 69kV Line 63 (D-Line)	41	50,000
		C24175	03303 Hopkinton Substation (Dist Line)	36	200,000
		C24176	03304 Hopkinton Substation (Dist Sub)	36	2,600,000
		C27222	03833 West Farnum - Rem. Dist. Equipment	41	10,000
		C28628	03528 NEWPORT Load Relief - Phase 2	41	50,000
		C28851	03655 Recon. 38F5 and 2227 Greenville Ave	27	50,000
		C28884	04415 Install Johnston 18F10 Feeder	35	250,000
		C28920	03419 New Substation West Warwick	39	300,000
		C28921	04414 Install 4 dist. Fdrs West Warwick	39	50,000
		C28932	03654 Recon. 0.75 Miles Segment of 2232	30	50,000
		C33535	04443 Johnston Sub 12.47 kV Expansion	35	500,000
		C34002	03435 Johnston Sub 12kV Epansion Getaways	35	100,000
		C36072	04442 Johnston #18 Substation Expansion	35	1,000,000
		C36397	04403 Clarkson - new 13F10 feeder (line)	31	160,000
		C36450	09296 Tower Hill New 88F7 Fdr (D-Line)	41	50,000
		C36515	09313 Kilvert St Substation (D-Sub)	42	100,000
		C36516	09303 Kilvert St Substation (D-Line)	42	300,000
		C36522	09312 Kilvert St Install TB#2 (D-Sub)	39	990,000
		CD0649	17046 Gate 2 Substation (D-Sub)	41	70,000
		CD0972	11915 New Highland Drive Substation - DSub	42	2,250,000
		CD0978	11916 New Highland Drive Substation - DLine	42	675,000
		CD1025	19245 Converting Customers to 127W41 from 127W43	23	72,000
		COS016	03543 Ocean St-Dist-Load Relief Blanket	49	239,000
		PPM 11664	11664 CLARKE 65J12 Feeder Upgrade (D-Sub)	37	100,000
		PPM 11665	11665 CLARKE St Feeder Upgrades (D-Line)	37	25,000
		PPM 13243	13243 KENTS CORNER transformer contingency and 47J4 feeder Load Relief	37	150,000
		PPM 15721	15721 Kent County 2nd Transformer (D-Sub)	41	350,000
		PPM 18075	18075 Kents Corner47- Feeder 47J3	46	150,000
		PPM 18350	18350 Wakefield 17F1 Feeder Upgrades	31	100,000
		PPM 18538	18538 Warwick Sub 52F3 Feeder Upgrade	37	250,000
		PPM 18577	18577 Woonskt Sub-Add new fdr pos for Mass load	30	75,000
		PPM 18578	18578 Woonskt-Add new feeder to Mass load	30	150,000
		PPM 19203	19203 Kent County 2nd Transformer (D-Line)	41	10,000
		RESERVE 049_016 SUB	03701 Reserve for Load Relief Unidentified Specifics & Schedule Changes (substation) - 49	34	(3,404,500)
	Load Relief Total				**10,396,500**
	Reliability - Dist	C05461	03250 FH - OS Feeder Hardening	40	200,000
		C05524	03382 IE - OS Cutout Replacements	40	300,000
		C35726	04432 EMS- Narragansett Electric	40	200,000
		CD0526	17312 EMS Add-Peacedale 59 RI	41	29,000
		CD0528	17651 EMS Expansion - Natick 29 Substation	34	100,000
		CD0529	17735 EMS Expansion - Hospital Sub 146	34	100,000
		CD0530	17737 EMS Expansion - Elmwood Outdoor 7	41	100,000
		CD0531	17736 EMS Expansion - Division Street 61	41	20,000
		CD0533	17743 EMS Expansion - Lincoln Ave 72	41	294,000
		CD0534	17742 EMS Expansion - Old Baptist 46	41	10,000
		CD0916	18762 Wood River - EMS Expansion	48	12,500
		COS015	03548 Ocean St-Dist-Reliability Blanket	49	1,232,000
		PPM 17747	17747 EMS Expansion - Hopkins Hill 63	34	50,000
		PPM 19184	19184 Tunk Hill Road, Scituate RI, Storm Hardening	30	1,000,000
		PPM 19782	Volt/Var Management	34	500,000
		RESERVE 049_015 LINE	03710 Reserve for Reliability Unidentified Specifics & Schedule Changes - 49	34	(2,000,000)
	Reliability - Dist Total				**2,147,500**
System Capacity & Performance Total					**12,544,000**
Grand Total					**59,600,000**

Section 3

Vegetation Management Program

FY 2014 Electric ISR Plan

Vegetation Management Program
FY 2014 Proposal

The Company's Vegetation Management ("VM") Program is an essential component of the Company's plan to maintain the safety and the reliability of its electric distribution network. Trees are an important concern for several reasons. Tree contact with the electric distribution system increases the risk of electric shock to the public, slows the restoration of critical infrastructure and may increase the risk of fire. Trees can also be a significant deterrent to reliability since tree contact with the distribution system during windy/stormy conditions may cause a phase to phase fault, which will trip either a line fuse, pole recloser or a station breaker and cause a service interruption. As shown in Chart 1, excluding major event days, trees were responsible for 21 percent of customers interrupted from 2007-2011. As shown in Chart 2, including major event days, trees were responsible for 26 percent of customers interrupted from 2007-2011.

Chart 1: Customer Interruptions by Cause (excluding PUC Major Event Days)

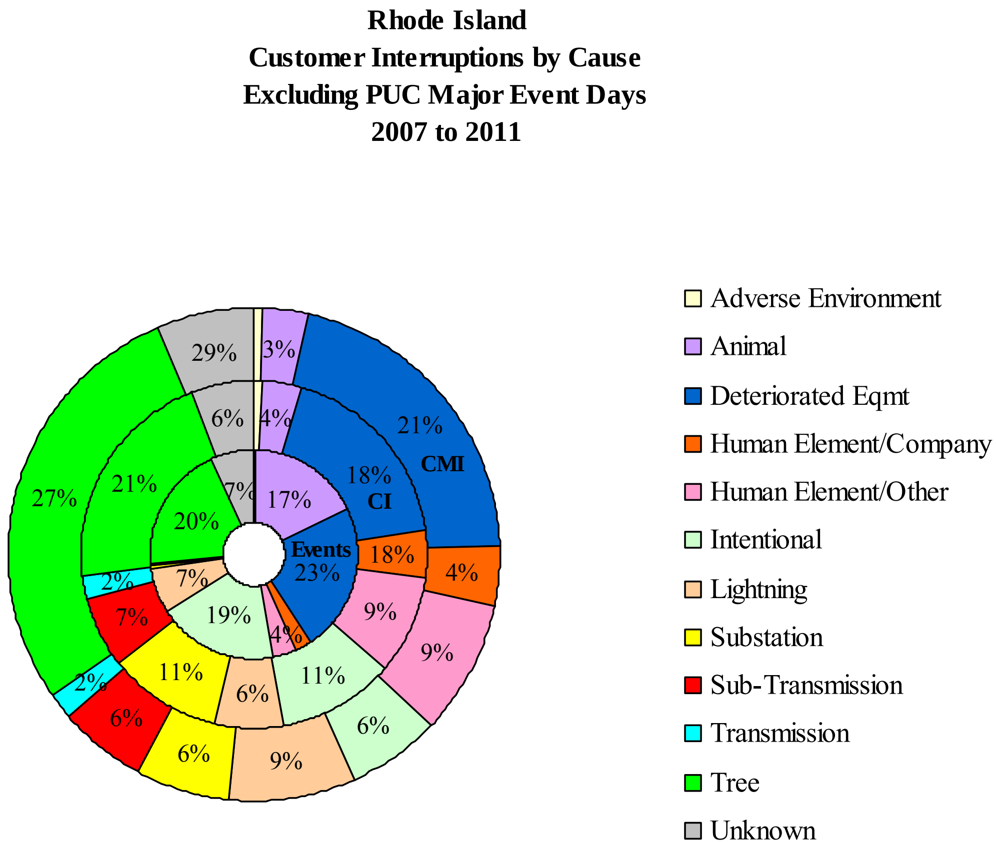
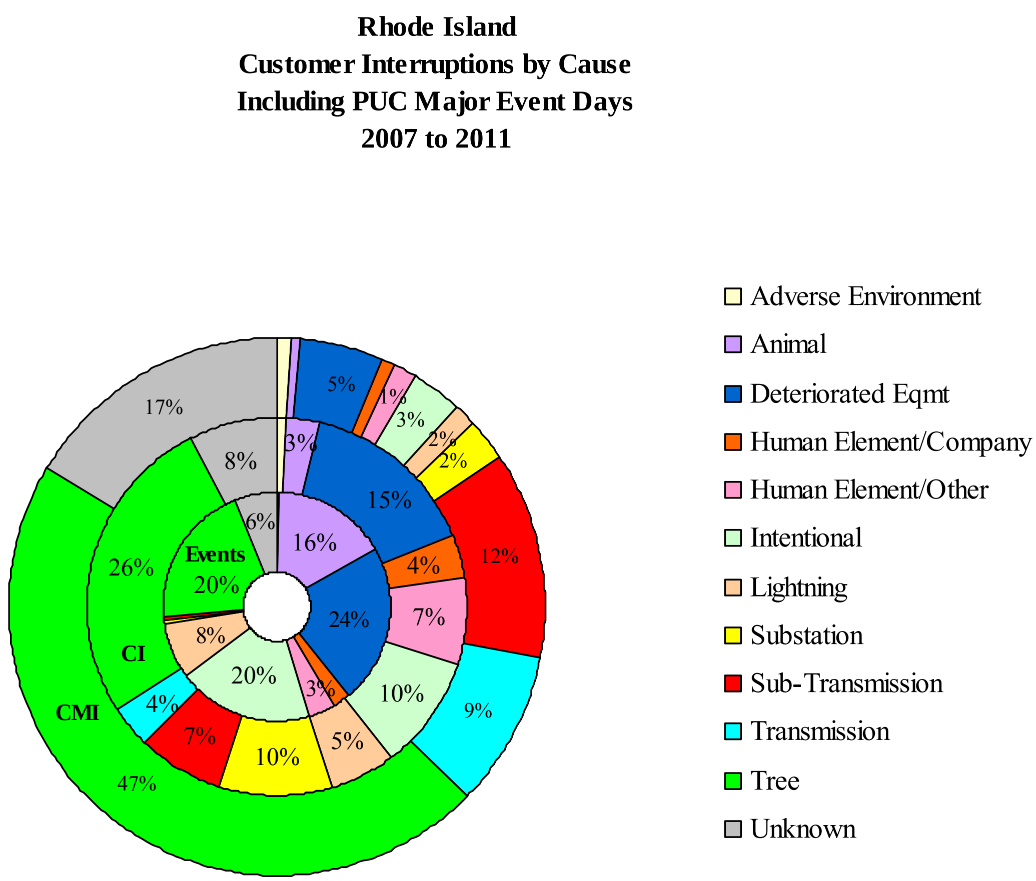


Chart 2: Customer Interruptions by Cause (including PUC Major Event Days)



The Company has developed a strong VM program which provides a measure of safety for the public/workforce, favorable operational efficiency, and minimizes the number of customer interruptions due to trees. The Company's VM program consists of several different activities, each addressing a different aspect of utility vegetation management.

Cycle Pruning - The Company spends approximately 65 percent of its VM budget on Cycle Pruning, a program designed to ensure that the vegetation growth along the overhead portion of the Company's distribution network does not interfere with the safe and reliable performance of the electric network. Cycle Pruning consists of the scheduling of every distribution circuit for pruning on a fixed timeframe or rotation. The pruning work performed is based on a dimension clearance specification. Cycle Pruning is designed to maintain an acceptable clearance between overhead conductors and vegetation to minimize the safety risk to the public and utility workforce. A stable, consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a best utility practice.

Consistent circuit pruning also helps maintain service reliability and supports efficient management of the overhead network. Managing the vegetation along the network helps to avoid interruptions caused by phase to phase tree contact and makes the network more accessible to line crews so they can restore power quickly following an interruption. Cycle Pruning also provides crews the clearance necessary to accurately inspect circuits and to more efficiently perform any required maintenance which also helps avoid interruptions.

The Company recommends a four-year interval as the optimum pruning cycle for the Rhode Island overhead distribution assets based on tree growth rates and the acceptable clearance dimensions obtained at the time of pruning. To maintain this four-year pruning interval, approximately 1,300 miles need to be pruned each year, and the FY 2014 plan calls for pruning 1,321 miles. The estimated cost for cycle pruning in FY 2014 is $5.230 million, or approximately $3,959 per mile. This cost per mile figure is based on the cost per mile in the last full year of pricing available (FY 2012) plus a three percent inflation factor.

Enhanced Hazard Tree Mitigation ("EHTM") - Hazard tree removal, as part of a complete utility vegetation management program, has become a best industry practice as well. Full tree and large limb failures have been shown to account for a significant portion of customer interruptions, not only in Rhode Island but also in other states. Using three years of tree-related interruption data for Rhode Island one can see that fallen trees account for 40 percent of tree-related customer interruptions ("CIs").

To address this issue, in 2007, the EHTM program was implemented to identify and remove dying or structurally weakened trees and overhanging leads along the three phase sections of distribution circuits. The three phase portion of the circuit is the most susceptible to tree caused faults and also serves the highest number of customers per exposed mile, thus intuitively providing the highest benefit per hazard tree removal dollar. EHTM uses an industry leading tree risk assessment protocol to identify hazard trees. The EHTM portion of the program historically accounts for approximately nine percent of the overall VM budget.

The purpose of the EHTM program is primarily to provide a reliability benefit. The hazard tree mitigation program targets the mainline portion of the Company's worst performing circuits where tree caused phase to phase faults will interrupt the entire population of customers on that circuit. To demonstrate these benefits and to meet the requirements of the FY 2012

Rhode Island Electric ISR Plan, a study of the Company's EHTM program was performed.[12] The results show an average improvement in tree-related Customers Interrupted (CI) by circuit of 75 percent for the first year following project completion. The EHTM program can, therefore, significantly improve the customer's service reliability on targeted circuits.

As a secondary benefit, the hazard tree mitigation program reduces repair costs. Hazard trees are designated as such because they have a high probability of failing and causing damage to Company equipment. Within the same benefit study referred to above, the Company estimated a 47 percent reduction in annual repair costs on a circuit where EHTM has been employed. The costs can be either capital or O&M, or both. The reduced repair costs would be reflected in historical capital damage failure spending levels, which are used to estimate proposed budget levels.

Given that trees continue to be a major cause of customer interruptions and in light of the significant reliability benefits associated with EHTM, the Company proposes a FY 2014 budget amount below the total amount approved in FY 2013 for the combined EHTM and post-Tropical Storm Irene EHTM, but similar to historical spending excluding post-Tropical Storm Irene EHTM. The combined spending for those two separate activities was $1.167 million. For FY 2014, the Company proposes a reduction of approximately 36 percent from FY 2013 levels to $0.750 million for the full EHTM program. With the EHTM funding the Company will also look at a new element of vegetation mitigation work targeting areas or pockets of poor performance. This new approach piloted in FY 2013 uses multiple fuse trip locations caused by trees queried from interruption records to target field condition inspections and follow-up work

[12] Electric ISR Plan FY 2012 Vegetation Management Cost Benefit Report, filed September 5, 2012.

to mitigate the service reliability issue. This approach helps focus mitigation in areas that otherwise may be missed by the current circuit SAIFI reliability model approach which focuses only on three phase sections of a circuit.

Sub-Transmission - This category includes vegetation management activities for the sub-transmission ("Sub-T") right-of-way ("ROW") network. Much like distribution cycle pruning, the Sub-T circuits are treated on a four-year cycle but, because of the smaller population of circuits, are not as easily balanced year to year. The FY 2014 schedule is clearly the heaviest of years and includes the off-road ROW edge or sideline pruning and hazard tree removal work on thirteen circuits estimated to cost $0.486 million, on-road pruning of eight circuits estimated to cost $0.103 million and the off-road floor treatment (selective herbicide treatments) on eleven circuits estimated to cost $0.135 million. The total cost for the required FY 2014 sub-transmission vegetation management work is $0.724 million. As shown in Chart 3 below, this is the heaviest year for sub-transmission work since the inception of the Electric ISR Plan process. The sideline pruning and hazard tree work is the most costly and is based on a price of approximately $9,896 per mile while the floor treatment cost per acre is approximately $610 per acre.

Chart 3: Sub-Transmission Vegetation Management Miles/Acres

Sideline Pruning and Hazard Tree Removal (miles)

FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
24.26	20.76	12.10	28.51	59.52

Floor Treatment (acres)

FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
335.93	234.48	88.67	100.68	222.05

Police Detail/Flagman - To safely perform the Cycle Pruning and EHTM, the Company must hire police details and flagman. The levels of required details vary by town and traffic/road condition. This portion of the VM budget is driven by the work plan and on the hourly rates set by the municipalities. Police/flag details generally consume less than five percent of the annual budget but that percentage is generally on the increase as more towns begin to require the use of their own uniformed police officers for flagging details.

Core Activities - The Company performs several other essential VM activities to efficiently maintain the safety and reliability of the network and to address customer needs. In contrast to Cycle Pruning or EHTM, the Company has very little discretion over the timing of these activities. This work includes responding to customer requests for vegetation-related work due to safety and reliability concerns. It also includes response to requests for interim or spot trimming by circuit patrols in locations where vegetation growth has exceeded normal conditions or where the patrols have identified other vegetation-related reliability concerns. Responding to emergency calls to remove sporadic trees/limbs from wires and to perform vegetation work necessary to restore power to customers is another important core activity performed by forestry crews. Spending for each core activity varies from year-to-year depending on the customer calls, weather, and system requirements. Each core activity separately consumes a small and variable proportion of the overall budget, but taken together these activities generally account for 17 percent of the VM budget. The expected spend for this category for FY 2014 is $1.247 million, which is based on a three percent inflation factor.

Fiscal Year 2014 Vegetation Management Budget

As detailed in Chart 4 below, the Electric ISR Plan proposes to spend approximately $8.476 million for VM in FY 2014, an increase of five percent above the amount requested and approved for FY 2013.

Chart 4: Vegetation Management Spending
(000's)

	FY 2010	**FY 2011**	**FY 2012**	**FY 2013 Forecast***	**FY 2014 Proposed**
Cycle Prune (Base)	$ 4,552	$ 2,732	$ 5,451	$ 5,150	$ 5,230
Hazard Tree – EHTM	$ 709	$ 235	$ 806	$ 750	$ 750
Post Irene - EHTM	$ -	$ -	$ -	$ 367	$ -
Sub-T (off & on road)	$ 302	$ 235	$ 392	$ 290	$ 724
Police/Flagman Detail	$ 241	$ 215	$ 461	$ 750	$ 525
All Other Activities (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$ 1,078	$ 1,189	$ 1,066	$ 1,211	$ 1,247
Total	**$ 6,882**	**$ 4,606**	**$ 8,176**	**$ 8,518**	**$ 8,476**

* This is the 2nd Quarter Electric ISR Plan forecast (as filed on November 30, 2012). The FY 2013 approved total budget is $8.256M. The variance in FY 2013 is attributable to Police/Flagman details, with all other components on budget.

The entire FY 2014 budget of $8.476 million pertains to VM spending necessary for the safety and service reliability of the Company's electric system. Verizon does not agree to contribute to the Company's tree trimming (vegetation management) cost on the basis that Verizon crews perform any required tree trimming for Verizon service work at the time such work is performed. This is not inconsistent with the Company's vegetation management practice given that the Company's tree trimming specification is designed and performed exclusively to address the safety and reliability needs of the electric system, without any consideration whatsoever of communication company needs. The Company's vegetation management program is implemented exactly the same across all overhead miles regardless of pole ownership. The Company's pruning and hazard tree specification, the work planning models and vegetation management work practices make no consideration for pole ownership, as the vegetation adjacent to a jointly owned pole, no matter which company's maintenance area, is pruned to the same specification as the vegetation adjacent to a solely owned pole.

Section 4

Inspection and Maintenance Program

FY 2014 Electric ISR Plan

Inspection and Maintenance Program
FY 2014 Proposal

Consistent with the Company's condition based asset management approach, the Company has implemented an inspection and maintenance ("I&M") program ("I&M Program"). To date, the Company has inspected 32 percent of its overhead distribution system. The Company agreed with the Division in previous ISR discussions that construction activities within the I&M Program would commence after the completion of the Feeder Hardening Program. To date, the repair work generated from these inspections has been limited to emergency items and a small ramp up, since the completion of the Company's Feeder Hardening Program mid-way through this fiscal year.

The FY 2012 Electric ISR Plan included only inspections of the overhead distribution system as the Company was actively pursuing its reliability based Feeder Hardening Program at that the same time. The FY 2013 Electric ISR Plan included both inspections and some repairs, but was limited in scale as the Company was also completing its Feeder Hardening program. The goal of the I&M Program going forward is to achieve a five-year cycle in which all feeders are inspected and have repairs completed. The proposed spending for FY 2014 represents a significant increase in spending when compared to recent spending on the Feeder Hardening program, and is based on inspection results to date. The plan for FY 2014 represents a ramp up such that 80 percent of the items identified as deteriorated are replaced within a five-year period and certain items that do not represent deterioration concerns, such as additional equipment grounding, are addressed over a 15-year horizon. The Company believes the extended horizon for the equipment grounding, primarily on down guys, is acceptable as there have been no reported incidents of elevated voltages found during contact voltage testing.

In addition to continuing to inspect its overhead distribution system, the Company is expanding the I&M Program to include inspections of its sub-transmission system and its manhole-based underground assets. For FY 2014, the Company proposes the following modifications to the program:

- Adjust the distribution overhead inspection cycle from a six-year cycle to a five-year cycle, which will provide new inspection results on approximately 20 percent of its overhead distribution system per year. Moving to a five-year cycle has been recommended by the Division and agreed to by the Company in Docket No. 4237[13]. This will maintain efficiencies with the elevated voltage inspection program as elevated voltage testing will be done on the same cycle as the inspections. A five- year cycle is considered standard in the industry[14].
- Add sub-transmission overhead assets to the program on a five-year cycle. Currently, there is no systematic inspection program currently in place for sub-transmission overhead assets. These assets are similar in age and condition to distribution overhead assets and the Company recommends they be added to the program on the same inspection cycle.
- Add underground assets to the program on a fifteen year cycle. Working inspections are currently performed by crews prior to beginning work, but it is not documented for use as part of the asset management process. Based on the Company's past experience in other jurisdictions, a five-year cycle is not

[13] The Company's proposed Contact Voltage Plan in Docket 4237 was approved by the Commission in an Open Meeting on October 4, 2012, with one addition. The Commission ordered the Company to obtain cost estimates for the Company's proposed schedule for mobile testing of 40 percent of the contact voltage risk areas during the first year with 20 percent each year thereafter as well as for performing testing mobile for all contact voltage risk areas in the first year, and 20 percent each year thereafter.
[14] Docket 4237, Gregory L. Booth and Micheal W. White Testimony, September 18, 2012, page 43.

warranted and the Company is planning to utilize a fifteen-year cycle for its underground assets.

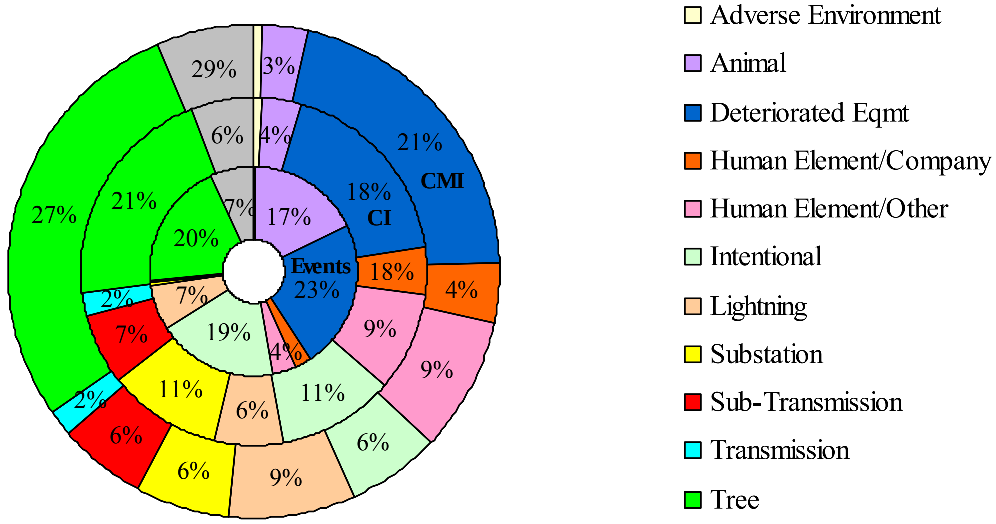
- Adjust the manual contact voltage testing cycle to a five-year cycle from a six-year cycle for distribution overhead. Moving to a five-year cycle has been recommended by the Division and agreed to by the Company in Docket No. 4237.
- Adjust the manual contact voltage testing cycle for metallic street lights from a five-year cycle to a three-year cycle. Moving to a three-year cycle for street light elevated voltage testing has been recommended by the Division and agreed to by the Company in Docket No. 4237.
- Add a mobile contact voltage testing program for "Designated Contact Voltage Risk Areas" as required in Docket No. 4237.

The primary driver of the I&M program is to address deteriorated assets to ensure the distribution and sub-transmission system is safe, reliable and environmentally sound. Asset replacement prior to failure provides incremental safety benefits for both the public and our employees. Implementation of this program should minimize potential safety issues relating to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. This program also provides for the avoidance of potential environmental problems such as insulating fluid leaks/spills from assets such as transformers and capacitor banks. The program is intended to satisfy section 214 of the National Electric Safety Code ("NESC"), which outlines inspection of equipment guidelines for electric utilities.

In addition to addressing deteriorated assets, the data collected from the inspections enhances the Company's Asset Management reviews and the development of projects and programs to maintain reliability performance and customer satisfaction. Indeed, as shown in Chart 1 below, from 2007-2011, excluding PUC major event days, deteriorated equipment accounts for 18 percent of customers interrupted and lightning accounts for six percent of customers interrupted.

Chart 1: Customer Interruptions by Cause

Rhode Island
Customer Interruptions by Cause
Excluding PUC Major Event Days
2007 to 2011



The Company believes that the I&M Program is essential to fulfilling its obligation to provide safe, reliable and cost effective electric delivery service to customers in Rhode Island and the Company has agreed with the Division to assess the costs and benefits of the Inspection and Maintenance Program on an ongoing basis, with the first assessment to be provided in August 2014.

The Company's proposal for each of the program components are as follows:

- Distribution overhead I&M repairs will be ramped up in FY 2014, with the full ramp up to the five-year repair cycle occurring in FY 2015, with the exception of certain grounding items.
- Sub-transmission overhead I&M will begin in FY 2014 with inspections and engineering only, repairs will commence in FY 2015, other than immediate issues.
- Underground I&M inspections will continue to be performed as part of normal working inspections for the next several years of the program. Repairs will commence in FY 2015, other than immediate issues. The Company will start to track results of the inspections in FY 2014.
- Overhead Manual Contact Voltage testing will be performed as part of the cycle inspections.
- Underground Manual Contact Voltage testing will continue on the five-year cycle.
- Street Light Manual Contact Voltage testing will move from a five-year to a three-year cycle.

- Mobile Contact Voltage Testing will commence in the FY 2014 ISR. By statute, the Company will conduct an initial survey of no less than 40 percent of designated contact voltage risk areas and thereafter beginning July 1, 2013 to annually survey no less than 20 percent of designated contact voltage areas. The Commission has requested the Company to obtain pricing for mobile surveying and completion of all designated contact voltage risk areas to be complete in one year. The Company has provided a recommendation for completing mobile surveying of all designated contact voltage risk areas in the first year in Docket 4237, and those costs are included in this ISR plan. The Commission will dictate the final recommended schedule for mobile surveying, and this ISR adjusted if necessary.

Fiscal Year 2014 Inspection and Maintenance Budget

As shown in Chart 2 below, the Company proposes a total I&M Program budget of approximately $16.0 million for FY 2014. The associated capital costs for this program are included in the capital budgets provided in Section 2 of this Electric ISR Plan. The O&M components of the I&M program total approximately $3.8 million. Sub-Transmission Overhead I&M, Underground I&M and Mobile Elevated Voltage Testing are new to both the I&M program and the Electric ISR Plan. Overhead and underground manual contact voltage testing is work that has been performed previously and included in base rates. Starting in FY 2014 overhead and underground manual contact voltage testing will be included in the Electric ISR Plan and removed from base rates.

Chart 2: Inspection and Maintenance Program Costs

	Total
Capital Costs (1)	**$8,614,600**
Opex Related to Capex	*$1,286,300*
Inspections and Repair Related Costs	*$2,492,700*
Total Operation and Maintenance Expenses	**$3,779,000**
Removal Costs	**$3,599,000**
Total Program Costs	**$15,992,600**

(1) Capital costs are included in the total capital cost of $59.6 million as discussed in Section 2.

Section 5

Revenue Requirement

FY 2014 Electric ISR Plan

Revenue Requirement
FY 2014 Proposal

The attached proposed revenue requirement calculation reflects the revenue requirement related to the Company's proposed investment in its Electric Infrastructure, Safety, and Reliability ("ISR") Plan ("ISR Plan") for the fiscal year ("FY") ended March 31, 2014. It is important to note that the revenue requirement for the FY 2014 ISR recovery mechanism excludes amounts embedded in base rates in Docket No. 4323 for FYs 2012, 2103, and 2104 investments.

As shown on Page 1, Column (c) of Attachment 1 to this Section, the Company's FY 2014 Electric ISR Plan revenue requirement amounts to $12,133,495 and consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, and the Company's Inspection and Maintenance ("I&M") Program, and (2) the Company's capital investment in electric utility infrastructure. Lines 1 and 2 of that column reflect the forecasted FY 2014 revenue requirement related to O&M expenses for VM and I&M of $8,476,000 and $3,615,251, respectively.

The FY 2014 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $42,244 is shown on Line 8, consisting of the $103,194 revenue requirement on FY 2014 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 2, plus the FY 2014 revenue requirement on incremental non-growth ISR capital investment of $-0- and $(60,950) for FY 2013 and FY 2012 incremental investments, respectively. The total annual FY 2014 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $12,133,495, as reflected in Column (c) on Line 9, and is equal to the sum of Lines 3 and 8.

For illustration purposes only, Column (d) of Page 1 provides the FY 2015 revenue requirement for the respective vintage year capital investments as calculated on Attachment 1, Pages 2 and 3. It is important to note that these amounts will be trued up to actual investment activity after the conclusion of the FY, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

Impacts of Base Rate Case Docket No. 4323 on FY 2014 Electric ISR Revenue Requirement

In April 2012, the Company filed an application with the Commission seeking a change in base rates for its electric and gas distribution businesses. The application was assigned Docket No. 4323. The test year used in the Company's request was calendar year 2011. The effective date of new rates in that proceeding is February 1, 2013 for a Rate Year ending January 31, 2014. On October 19, 2012, the Company entered into a settlement agreement with the Rhode Island Division of Public Utilities and Carriers (the "Division"), and the U.S. Department of the Navy (the "Navy") with regard to the Company's base rate change request. On November 14, 2012, the Company entered into an amended settlement agreement (the "Amended Settlement Agreement") with the Division and the Navy with regard to the Company's base rate request. The Commission approved the Amended Settlement Agreement on December 20, 2012. The base rate change request and associated Amended Settlement Agreement has affected various aspects of the FY 2014 Electric ISR Plan as follows:

> All O&M costs associated with the Company's VM and I&M programs were excluded from the base rate request because these costs are recoverable through

the electric ISR reconciliation mechanism. The only exception is certain voltage inspection monitoring costs that are being recovered in base rates and therefore have been excluded from the ISR reconciliation mechanism.

The FY 2014 revenue requirement associated with the Company's capital investment in electric utility infrastructure is based on incremental capital investment in excess of capital investment that has been reflected in rate base in the Company's base rate case. The FY 2014 ISR revenue requirement has been calculated on estimated FY 2014 incremental capital investment, as well as on incremental capital investment for FY 2012 and FY 2013 because some or all of the capital investment for these years will occur beyond the test year ended December 31, 2011.

The FY 2014 electric infrastructure revenue requirement has been calculated based upon the agreed to level of embedded depreciation expense and associated composite depreciation rate, effective property tax rate, capital structure, and cost of capital rates (including a 9.50 percent equity return) per the Amended Settlement Agreement.

The method used to recover property tax expense under the ISR has been modified by the Amended Settlement Agreement. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company shall include an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The ISR property tax recovery will also include the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative ISR net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery calculation.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2014 Electric ISR Plan revenue requirement includes $8,476,000 of VM and $3,615,251 of I&M expenses as shown on Page 1, Lines 1 and 2 in Column (c) of the attachment. As described in Sections 1 and 4 of this Plan, the Electric ISR Plan now includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program ("Contact Voltage Program"), mandated by R.I.G.L. §39- 2-25 and approved by the Commission in Docket No. 4237[15]. The recovery of Contact Voltage Program costs are net of $163,749 of voltage monitoring costs included in base rates in the Company's base rate request in Docket No. 4323. Also, the FY 14 Contact Voltage Program costs include a full year of estimated FY 2014 costs as approved by the Commission in Docket No. 4237.

Electric Infrastructure Investment

Incremental Capital Investment

As noted above, Pages 2 and 3 of the Attachment 1 to this Section calculate the revenue requirement of incremental capital investment associated with the Company's FY 2014 Electric ISR Plan plus the FY 2014 revenue requirement on the incremental capital investment associated with the Company's FY 2013 and 2012 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4323 for each of those fiscal years; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. In the rate proceeding, Docket No. 4323, the Company proposed to maintain consistency with the existing ISR mechanism for the FY 2012 and FY 2013 periods. The Company did this by reflecting the FY 2012 and FY 2013 level of ISR-eligible capital additions previously approved by the Commission in those years for purposes of rolling forward the level of rate base from the end of the December 31, 2011 test year to the January 31, 2014 end of the rate year in Docket No. 4323. Because there was no approved FY 2014 Electric ISR Plan at the time the Company filed its rate request, for the April 2013 through January 2014 period, the

[15] R.I.G.L. §39-2-25(6)(c).

Company assumed the same level of annual ISR-eligible capital investments as those approved for FY 2013, prorated for that ten-month period. Incremental electric capital investment for this purpose is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's base rates, net of depreciation expense attributable to general plant.

Page 6 of Attachment 1 calculates the incremental ISR capital investment and the related incremental cost of removal and incremental retirements for the FY 2014 electric ISR revenue requirement. The calculation compares ISR-eligible capital investment, cost of removal and retirements for FY 2012 through FY 2014, to the corresponding amounts reflected in Docket No. 4323. Column (a) on Page 6 reflects FY 2012 **actual** ISR-eligible capital investment, cost of removal and retirements which are compared to the amounts estimated in rate base in Docket No. 4323 for FY 2012. The comparable columns for FY 2013 and FY 2014 are represented in Columns (b) and (c), however the comparison of the capital investment, cost of removal and retirements in rate base in Docket No. 4323 are made to **estimated** ISR-eligible amounts since the actual amounts will not be known until those years are completed. For FY 2013, estimated ISR-eligible amounts are the same amounts that were reflected in rate base in Docket No. 4323. Consequently, the incremental Electric ISR Plan capital investment, cost of removal and retirements to be used in the revenue requirement calculation for vintage year FY 2013 investments for the FY 2014 revenue requirement are $-0-. Actual ISR-eligible amounts for FY 2013 will be known and reflected in the Company's FY 2015 Electric ISR Plan filing. Finally, estimated ISR-eligible capital investment, cost of removal and retirements for the twelve months of FY 2014 are being compared to the estimated amount of ISR-eligible investment included in rate base in Docket No. 4323 through the rate year ending January 31, 2014 for determining the incremental amounts to be included in this proceeding. As described above, because all ISR-eligible investment is fully reconciling through the ISR reconciliation mechanism, the Company used the FY 2013 approved level of additions to plant in-service as a proxy for estimated FY 2014 investment in the rate case. The capital investment amounts on Lines 1 through 3 on Page 6 are broken down further into "nondiscretionary" and "discretionary" categories on Pages 7 through 9. For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: "nondiscretionary" capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and "discretionary" capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined "nondiscretionary" categories.

In the FY 2012 and FY 2013 electric ISR filings, the amount of capital additions ultimately allowable in the ISR Plan was limited to amounts no greater than the actual cumulative amount of capital spending on nondiscretionary projects, and no greater than the cumulative amount of discretionary project spend as agreed to by the Division and as approved by the Commission. The intent of this limitation on nondiscretionary projects was to ensure that capital investment incurred prior to the April 1, 2011 effective date of the ISR Plan, but placed in-service after that date, was not included in the ISR Plan revenue requirement. Upon the Commission's approval of the Amended Settlement Agreement in Docket No. 4323, effective February 1, 2013, all pre-ISR capital investment will effectively be embedded in rate base, and all ISR capital investment placed in-service subsequent to the effective date of new base rates will have been incurred subsequent to the commencement of the electric ISR program, thus alleviating the need for this limitation on nondiscretionary work. However, the limitation on discretionary projects as described above shall remain in place.

Electric Infrastructure Revenue Requirement

The revenue requirement calculation on incremental electric infrastructure investment for vintage year FY 2014 is shown on Page 2 of Attachment 1. The revenue requirement calculation incorporates the incremental Electric ISR Plan capital investment, cost of removal and retirements calculated on Page 6, which is the basis for determining the three components of the revenue requirement: (1) the return on investment (i.e. average ISR Plan rate base at the weighted average cost of capital); (2) depreciation expense; and (3) property taxes. The calculation on Page 2 begins with the determination of the depreciable net incremental capital that will be included in the ISR Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in ISR Plan rate base in determining depreciation expense. Retirements however, do not affect rate base as both "plant in service" and the "depreciation reserve" are reduced by the installed value of the plant being retired and therefore have no impact on net plant. For purposes of calculating the revenue requirement, plant retirements have been estimated based on the percentage of retirements to additions during FY 2012, and has been deducted from the total depreciable capital amount as shown on Lines 4 through 6. Incremental book depreciation expense on Line 15 is computed based on the net depreciable additions, from Line 6 at the 3.40 percent composite depreciation rate as approved in Docket No. 4065[16], and as shown on Line 12. The Company has assumed a half year convention for the year of installation. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cost of removal, as shown on Line 10, is combined with the incremental depreciable amount from Line 9 (vintage year ISR Plan allowable capital additions less non-general plant depreciation expense included in base distribution rates) to arrive at the incremental investment on Line 11 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 11, and accumulated depreciation and accumulated deferred tax reserves as shown on Lines 16 and 19, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 17 through 19, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate. The calculation of tax depreciation is described below. The average change in rate base is shown on Line 24.

Average rate base in the Electric ISR Plan revenue requirement is normally calculated as the average year-end cumulative change in rate base. However, because a portion of FY 2014 non-growth capital investment is reflected in the rate case and the other portion is not, a separate calculation was necessary to apportion the incremental non-growth capital for the year for purposes of determining the weighted average rate base for FY 2014 investment. This calculation is shown on Page 10 of Attachment 1. The portion of FY 2014 that falls outside of the rate year is the months of February and March of 2014; therefore, it is assumed that one-twelfth of total FY 2014 non-growth capital investment will be incurred in each of those months.

[16] The Commission did not change depreciation rates in the Company's base rate filing in Docket No. 4323.

For the remaining FY 2014 incremental non-growth capital investment (i.e. total incremental non-growth capital investment less the portion attributed to February and March of 2014), it is assumed that such remaining investment will be incurred evenly during the months of April 2013 to January 2014. The incremental investment for each month is then weighted for the period that such investment was outstanding during the year, generating a weighted average plant investment ratio of 16.25 percent (i.e. the ratio of the weighted average plant investment for the year over total incremental ISR capital investment). Average rate base on Line 24 of Page 2 for FY 2014 on vintage FY 2014 capital investment equals the year-end rate base from Line 23 times the 16.25 percent from Page 10. This amount is multiplied by the pre-tax rate of return agreed to in the Amended Settlement Agreement approved by the Commission in Docket No. 4323, as shown on Line 25, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 26. To this, incremental depreciation expense is added on Line 27, as are property taxes on Line 28, which are computed on net capital investment in the year following the investment to coincide with the timing in which property taxes are assessed. The sum of these three amounts reflects the annual revenue requirement associated with the capital investment portion of the Company's Electric ISR Plan on Line 29, which is carried forward to Page 1, Line 6, as part of the total Electric ISR Plan revenue requirement. A similar revenue requirement calculation for the vintage FY 2012 incremental ISR Plan capital investment is shown on Page 3. These capital investment revenue requirement amounts are added to the total O&M expenses on Line 3, Page 1, to derive the total FY 2014 Electric ISR Plan revenue requirement of $12,133,495 as shown on Line 9, and represents and incremental $1,606,595 increase from the FY 2013 Electric ISR Plan revenue requirement, as shown on Line 10.

Tax Depreciation Calculation

The tax depreciation calculations for FY 2014 and FY 2012 are provided on Pages 4 and 5 of Attachment 1, respectively. The tax depreciation amount assumes that a portion of the capital investment, as shown on Line 1 of those pages, will be eligible for immediate deduction on the Company's corresponding FY federal income tax return. This immediate deductibility is referred to as the capital repairs deduction[17]. In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Lines 4 through 12 on Page 5. During 2010, Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the "Act"), which provided for an extension of bonus depreciation. Specifically, the Act provides for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 2012. In accordance with the Act,

[17] During 2009, the Internal Revenue Service ("IRS") issued additional guidance, under Internal Revenue Code Section 162, related to certain work considered to be repair and maintenance expense, and eligible for immediate tax deduction for income tax purposes, but capitalized by the Company for book purposes. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in its FY 2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. Since that time, the Company has taken a capital repairs deduction on all subsequent FY tax returns. This has formed the basis for the capital repairs deduction assumed in the Company's revenue requirement. This tax deduction has the effect of increasing deferred taxes and lowering the revenue requirement that customers will pay under the capital investment reconciliation mechanism. The Company's federal income tax returns are subject to audit by the IRS. If it is determined in the future that the Company's position on its tax returns on this matter was incorrect, the Company will reflect any related IRS disallowances, plus any associated interest assessed by the IRS, in a subsequent reconciliation filing under the ISR Plan.

capital investments made from January 2012 through March 2012 are eligible for 50 percent bonus depreciation, as shown on Page 5, Line 10[18].

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System, or MACRS, tax depreciation rate. The amount of depreciation deducted for MACRS is added to the amount of capital repairs deduction plus the bonus depreciation deduction and cost of removal to arrive at total tax depreciation. These annual total tax depreciation amounts are carried forward to Line 13 and Line 11 of Attachment 1, Pages 2 and 3, for the respective years, and incorporated in the deferred tax calculation.

[18] The Company anticipates that the IRS will issue further guidance on this issue and, to the extent such guidance differs from the Company's interpretation of the 2010 Act, will reflect any resulting differences in a subsequent reconciliation filing under the ISR Plan.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Annual Revenue Requirement Summary

Line No.		As Approved Fiscal Year 2013 (a)	Effective February 1, 2013 (1/) (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)
	Operation and Maintenance (O&M) Expenses				
1	Forecasted Vegetation Management (VM)	$8,256,000	$8,256,000	$8,476,000	
2	Forecasted Inspection & Maintenance (I&M) O&M Expense	$2,270,900	$2,270,900	$3,615,251	
3	**O&M Expense Component of Revenue Requirement Subtotal**	$10,526,900	$10,526,900	$12,091,251	
	Capital Investment				
4	Actual Revenue Requirement on Incremental FY 2012 Capital included in Rase Base	$2,775,419	$0	($60,950)	($61,451)
5	Forecasted Annual Revenue Requirement on FY 2013 Capital included in Rate Base	$1,127,207	$0	$0	$0
6	Forecasted Annual Revenue Requirement on FY 2014 Capital included in ISR Rate Base			$103,194	$975,307
7	Less Settlement Agreement dated 1/31/12	($440,000)			
8	**Capital Investment Component of Revenue Requirement Subtotal**	**$3,462,626**	**$0**	**$42,244**	**$913,856**
9	**Total Fiscal Year Revenue Requirement**	**$13,989,526**	**$10,526,900**	**$12,133,495**	**$913,856**
10	**Total Incremental Fiscal Year Rate Adjustment**		**($3,462,626)**	**$1,606,595**	**N/A**

1/ Pursuant to the Settlement Agreement filed in Docket 4323, the Capital component of the FY 2103 ISR rate will be reduced to zero coincident with the effective date of new Base Rates.

Line Notes:
Column (a) - as Approved per R.I.P.U.C. Docket No. 4307
Column (c)
1 Projected Vegetation Management
2 Page 11, Line 3
3 Line 1 + Line 2
4 Page 3, Line 27
6 Page 2, Line 29
8 Line 4 through Line 7
9 Line 3 + Line 8
10 Current Year Line 9 - Prior Year Line 9

The Narragansett Electric Company
d/b/a National Grid
Computation of Electric Capital Investment Revenue Requirement
FY 2014 Investment

Line No.			Fiscal Year 2014 (a)	Fiscal Year 2015 (b)
	Capital Additions Allowance			
	Non-Discretionary Capital			
1	Lesser of Actual Cumulative Non-Discretionary Additions or Spending	Page 7 Line 3, Column (c)	$2,446,833	$0
	Discretionary Capital			
2	Lesser of Actual Cumulative Discretionary Capital Additions or Spending, or Approved Spending	Page 7 Line 6, Column (c)	$8,120,883	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2	$10,567,716	$0
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3	$10,567,716	$0
5	Retirements	Page 6 Line 9, Column (c)	$1,670,756	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6	$8,896,960	$8,896,960
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3	$10,567,716	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant 1/	$7,173,397	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9	$3,394,319	$3,394,319
10	Total Cost of Removal	Page 6 Line 6, Column (c)	$3,649,167	$3,649,167
11	**Total Net Plant in Service**	**Line 9 + Line 12**	**$7,043,486**	**$7,043,486**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065	3.40%	3.40%
13	Tax Depreciation	Page 4 Line 10	$5,937,342	$620,987
14	Cumulative Tax Depreciation	Prior Year Line 13 + Current Year Line 14	$5,937,342	$6,558,329
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50% *2/12; Column (b) = Line 6 * Line 12	$25,208	$302,497
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15	$25,208	$327,705
17	Cumulative Book / Tax Timer	Line 14 - Line 16	$5,912,134	$6,230,624
18	Effective Tax Rate		35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18	$2,069,247	$2,180,718
	Rate Base Calculation:			
20	Cumulative Incremental Capital Included in Rate Base	Line 11	$7,043,486	$7,043,486
21	Accumulated Depreciation	- Line 16	($25,208)	($327,705)
22	Deferred Tax Reserve	- Line 19	($2,069,247)	($2,180,718)
23	Year End Rate Base	Sum of Lines 20 through 22	$4,949,031	$4,535,062
	Revenue Requirement Calculation:			
24	Average Rate Base	Column (a) = Page 10 Line 15 * Line 23; Column (b) = (Prior Year Line 23 + Current Year Line 23) ÷2	$803,982	$4,742,047
25	Pre-Tax ROR	2/	9.70%	9.70%
26	Return and Taxes	Line 24 * Line 25	$77,986	$459,979
27	Book Depreciation	Line 15	$25,208	$302,497
28	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 10 - Line 8 -Line 16) * Property Tax Rate 3/	$0	$212,831
29	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**	**$103,194**	**$975,307**

1/ Depreciation Expense has been prorated for 2 months (February - March 2014)
2/ Weighted Average Cost of Capital per Settlement Agreement R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	5.01%	2.50%		2.50%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.19%	2.51%	9.70%

3/ Assumes an Effective Property Tax Rate of 3.98% subject to the true up per Settlement Agreement R.I.P.U.C. Docket No. 4323

The Narragansett Electric Company
d/b/a National Grid
Computation of Electric Capital Investment Revenue Requirement
FY 2012 Investment

Line No.			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)
	Capital Additions Allowance					
	Non-Discretionary Capital					
1	Lesser of Actual Non-Discretionary Capital Additions or Spending	Page 9 Line 3, Column (c)	($4,019,686)	$0	$0	$0
	Discretionary Capital					
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending	Page 9 Line 7, Column (c)	$4,163,942	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2	$144,256	$0	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3	$144,256	$0	$0	$0
5	Retirements	Page 6 Line 9, Column (a)	$19,938	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b), (c) & (d) = Prior Year Line 6	$124,318	$124,318	$124,318	$124,318
	Change in Net Capital Included in Rate Base					
7	Incremental Depreciable Amount	Column (a) = Line 4, Columns (b), (c) & (d) = Prior Year Line 7	$144,256	$144,256	$144,256	$144,256
8	Cost of Removal	Page 6 Line 6, Column (a)	($771,131)	($771,131)	($771,131)	($771,131)
9	**Total Net Plant in Service**	**Line 7 + Line 8**	**($626,875)**	**($626,875)**	**($626,875)**	**($626,875)**
	Deferred Tax Calculation:					
10	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065	3.40%	3.40%	3.40%	3.40%
11	Tax Depreciation	Page 5 Line 20, Column (a)	($655,837)	$2,172	$2,009	$1,859
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11	($655,837)	($653,665)	($651,656)	($649,797)
13	Book Depreciation	Column (a) = Line 6 * Line 10 * 50%; Columns (b), (c)&(d) = Line 6 * Line 10	$2,113	$4,227	$4,227	$4,227
14	Cumulative Book Depreciation	Prior Year Line 14 + Current Year Line 13	$2,113	$6,340	$10,567	$14,794
15	Cumulative Book / Tax Timer	Line 12 - Line 14	($657,950)	($660,005)	($662,223)	($664,591)
16	Effective Tax Rate		35.00%	35.00%	35.000%	35.000%
17	Deferred Tax Reserve	Line 15 * Line 16	($230,283)	($231,002)	($231,778)	($232,607)
	Rate Base Calculation:					
18	Cumulative Incremental Capital Included in Rate Base	Line 9	($626,875)	($626,875)	($626,875)	($626,875)
19	Accumulated Depreciation	- Line 14	($2,113)	($6,340)	($10,567)	($14,794)
20	Deferred Tax Reserve	- Line 17	$230,283	$231,002	$231,778	$232,607
21	Year End Rate Base	Sum of Lines 18 through 20	($398,706)	($402,213)	($405,664)	($409,062)
	Revenue Requirement Calculation:					
22	Average Rate Base	(Prior Year Line 21 + Current Year Line 21) ÷2			($403,939)	($407,363)
23	Pre-Tax ROR	1/			9.70%	9.70%
24	Return and Taxes	Line 22 * Line 23			($39,182)	($39,514)
25	Book Depreciation	Line 19			$4,227	$4,227
26	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 8 - Line 14) * Property Tax Rate 2/			($25,995)	($26,164)
27	**Annual Revenue Requirement**	**Sum of Lines 22 through 26** **3/**	**N/A**	**N/A**	**($60,950)**	**($61,451)**

1/ Weighted Average Cost of Capital per Settlement Agreement R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	5.01%	2.50%		2.50%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.19%	2.51%	9.70%

2/ Assumes an Effective Property Tax Rate of 3.98% subject to true up per Settlement Agreement R.I.P.U.C. Docket No. 4323
3/ Column (a) The FY 2012 Revenue Requirement on the FY 2012 Capital investment was reconciled in the FY 2012 Electric ISR Reconciliation Filing R.I.P.U.C. Docket No. 4218.
Column (b) The FY 2013 Revenue Requirement on the FY 2012 Capital Investment will be reconciled in the FY 2013 Electric ISR Reconciliation Filing due August 1, 2013.

The Narragansett Electric Company
d/b/a National Grid
Calculation of Tax Depreciation
On FY 2014 Capital Investment

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 2 Line 3		$10,567,716	
2	Capital Repairs Deduction Rate	Per Tax Department	1/	18.60%	
3	Capital Repairs Deduction	Line 2 * Line 3		$1,965,595	
	Remaining Tax Depreciation				
4	Plant Additions	Line 1		$10,567,716	
5	Less Capital Repairs Deductions	Line 3		$1,965,595	
6	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 4 - Line 5		$8,602,121	$8,602,121
7	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%
8	Remaining Tax Depreciation	Line 6 * Line 7		$322,580	$620,987
9	Cost of Removal	Page 2 Line 10		$3,649,167	
10	Total Tax Depreciation and Repairs Deduction	Lines 3 + Line 8 + Line 9		$5,937,342	$620,987

1/ Capital Repairs percentage is based on a three year average, 2010, 2011 and 2012 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions.

The Narragansett Electric Company
d/b/a National Grid
Computation of Electric Capital Investment Revenue Requirement
On FY 2012 Capital Investment

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)
	Capital Repairs Deduction						
1	Plant Additions	Page 3 Line 3		$144,256			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	18.60%			
3	Capital Repairs Deduction	Line 2 * Line 3		$26,832			
	Bonus Depreciation						
4	Plant Additions	Line 1		$144,256			
5	Less Capital Repairs Deduction	Line 3		$26,832			
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$117,424			
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	2/	85.00%			
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$99,810			
9	Bonus Depreciation Rate (April 2011 - December 2011)	1 * 75% * 100%		75.00%			
10	Bonus Depreciation Rate (January 2012 - March 2012)	1 * 25% * 50%		12.50%			
11	Total Bonus Depreciation Rate	Line 9 + Line 10		87.50%			
12	Bonus Depreciation	Line 8 * Line 11		$87,334			
	Remaining Tax Depreciation						
13	Plant Additions	Line 1		$144,256			
14	Less Capital Repairs Deduction	Line 3		$26,832			
15	Less Bonus Depreciation	Line 12		$87,334			
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$30,090	$30,090	$30,090	$30,090
17	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%	6.677%	6.177%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,128	$2,172	$2,009	$1,859
19	Cost of Removal	Page 3 Line 8		($771,131)			
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19		($655,837)	$2,172	$2,009	$1,859

1/ Capital Repairs percentage is based on a three year average, 2010, 2011 and 2012 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions.

2/ Since not all property additions qualify for bonus depreciation and because a project must be started after the beginning of the bonus period, January 1, 2008, an estimate of 85% is used rather than 100%.

The Narragansett Electric Company
d/b/a National Grid
FY 2012 - FY 2014 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Estimated Fiscal Year 2013 (b)	Estimated Fiscal Year 2014 (c)	
	Capital Investment					
1	ISR - Eligible Capital Investment	Col (a) FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) FY 2013 ISR Filing Docket No. 4307; Col (c) Proposed FY 2014 Capital Investment	$48,946,456	$51,366,341	$53,373,000	1/
2	ISR - Eligible Capital Additions included in Rate Base per R.I.P.U.C. Docket No. 4323	Schedule MDL-3-ELEC Page 53, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Col (c)= Line Note 3(e)	$48,802,200	$51,366,341	$42,805,284	1/
3	Incremental ISR Capital Investment	Line 3 - Line 4	$144,256	$0	$10,567,716	
	Cost of Removal					
4	ISR - Eligible Cost of Removal	Col (a) FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) FY 2013 ISR Filing Docket No. 4307; Col (c) Proposed FY 2014 Capital Investment	$5,807,869	$7,075,000	$9,545,000	
5	ISR - Eligible Cost of Removal in Rate Base per R.I.P.U.C. Docket No. 4323	Workpaper MDL-19-ELEC Page 2, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Col (c)= Line Note 3(e)	$6,579,000	$7,075,000	$5,895,833	
6	Incremental Cost of Removal	Line 4 - Line 5	($771,131)	$0	$3,649,167	
	Retirements					
7	ISR - Eligible Retirements/Actual	Col (a) FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) FY 2013 ISR Filing Docket No. 4307; Col (c)= Line 1 * 15.81%	$7,740,446	$8,416,000	$8,438,271	2/
8	ISR - Eligible Retirements/Estimated	Col (a) FY 2012 ISR Filing Docket No. 4218; Col (b) FY 2013 ISR Filing Docket No. 4307; Col (c)= Line 2 * 15.81%	$7,720,508	$8,416,000	$6,767,515	2/
9	Incremental Retirements	Line 7- Line 8	$19,938	$0	$1,670,756	

1/ Col (a) - Detail on Page 9
1/ Col (b) - Detail on Page 8
1/ Col (c) - Detail on Page 7
2/ Assumes 15.81% based on FY 2012 retirements as a percentage of capital investment

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric Capital Investment Summary

Line No.			Fiscal Year 2014 (a)	In Base Rates Included In Docket No. 4323 (b)	Amount to be Included in FY 2014 ISR (a) - (b) = (c)
	Non Discretionary Capital				
1	FY 2014 Proposed Non-Discretionary Capital Additions	Column (b) FY 2013 ISR Docket No. 4307 Schedule WRR-1 Page 2, Line 1 * 10/12	$26,296,000	$23,849,167	
2	FY 2014 Proposed Non-Discretionary Capital Spending		$26,559,000		
3	**Non Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending**	Column (a) Lesser of Line 1 or Line 2	**$26,296,000**	**$23,849,167**	$2,446,833
	Discretionary Capital				
4	FY 2014 Proposed Discretionary Capital Addtions	Column (b) FY 2013 ISR Docket No. 4307 Schedule WRR-1 Page 2, Line 2 * 10/12	$27,077,000	$18,956,118	
5	FY 2014 Proposed Discretionary Capital Spending		$33,041,000		
6	**Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Discretionary Capital Additions or Spending or Approved Spending**	Column (a) Lesser of Line 4 or Line 5	**$27,077,000**	**$18,956,118**	$8,120,883
7	**Total Allowed Capital Included in Rate Base Current Year**	Line 3 + Line 6	**$53,373,000**	**$42,805,284**	**$10,567,716**

Column (a) FY 2014 Proposed Capital Investment
Line 7 Column (b) - Refer to Schedule MDL-3-ELEC Page 53, Line 3(e) Docket No. 4323

The Narragansett Electric Company
d/b/a National Grid
FY 2013 Electric Capital Investment Summary

Line No.			Estimated Fiscal Year 2013	In Base Rates Included In Docket No. 4323	Incremental Capital
			(a)	(b)	(a) - (b) = (c)
	Non Discretionary Capital				
1	Actual Non-Discretionary Capital Additions	Col (a)&(b) FY 2013 ISR Filing - Docket No. 4307	$28,619,000	$28,619,000	
2	Actual Non-Discretionary Capital Spending		$30,428,000	$30,428,000	
3	**Non Discretionary Capital allowed in rate base is Equal to the lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending**	Column (a) Lesser of Line 1 or Line 2	**$28,619,000**	**$28,619,000**	$0
	Discretionary Capital				
4	Actual Discretionary Capital Addtions	Col (a)&(b) FY 2013 ISR Filing - Docket No. 4307	$22,747,000	$22,747,000	
5	Approved Discretionary Capital Spending		$26,112,000	$26,112,000	
6	**Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Discretionary Capital Additions or Spending or Approved Spending**	Coulmn (a) Lesser of Line 4 or Line 5	**$22,747,000**	**$22,747,000**	$0
7	**Total Allowed Capital Included in Rate Base Current Year**	Line 3 + Line 6	**$51,366,000**	**$51,366,000**	**$0**

The Narragansett Electric Company
d/b/a National Grid
FY 2012 Electric Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	In Base Rates Included In Docket No. 4323 (b)	Incremental Capital (a) - (b) = (c)
	Non Discretionary Capital				
1	Actual Non-Discretionary Capital Additions	Col (a) FY 2012 ISR Reconciliation Filing - Docket No. 4218 , Col (b) Schedule MDL-3-ELEC Page 53 - Docket No. 4323	$28,771,217	$30,087,700	
2	Actual Non-Discretionary Capital Spending		$26,068,014	$31,341,500	
3	**Non Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending**	Column (a) Lesser of Line 1 or Line 2	**$26,068,014**	**$30,087,700**	($4,019,686)
	Discretionary Capital				
4	Actual Discretionary Capital Addtions		$22,878,442	$18,714,500	
5	Actual Discretionary Capital Spending		$24,424,047	$27,036,150	
6	Approved Discretionary Spending		$27,036,150	$27,036,150	
7	**Discretionary Capital Allowed in Rate Base is Equal to the Lesser of Actual Cumulative Discretionary Capital Additions or Spending or Approved Spending**	Coulmn (a) Lesser of Line 4 or Line 5 or Line 6	**$22,878,442**	**$18,714,500**	$4,163,942
8	**Total Allowed Capital Included in Rate Base Current Year**	Line 3 + Line 7	**$48,946,456**	**$48,802,200**	**$144,256**

The Narragansett Electric Company
d/b/a National Grid
Calculation of FY 2014 Weighted Average Rate Base Ratio

Line No.	Month No.	Month	FY 2014 Plant Additions	In Rates	Not In Rates	Weight	Weighted Average
			(a)	(b)	(c) = (a) - (b)	(d)	(f) = (d) * (c)
1				$51,366,341			
2	1	Apr-13	$4,447,750	$4,280,528	$167,222	0.958	$160,254
3	2	May-13	$4,447,750	$4,280,528	$167,222	0.875	$146,319
4	3	Jun-13	$4,447,750	$4,280,528	$167,222	0.792	$132,384
5	4	Jul-13	$4,447,750	$4,280,528	$167,222	0.708	$118,449
6	5	Aug-13	$4,447,750	$4,280,528	$167,222	0.625	$104,513
7	6	Sep-13	$4,447,750	$4,280,528	$167,222	0.542	$90,578
8	7	Oct-13	$4,447,750	$4,280,528	$167,222	0.458	$76,643
9	8	Nov-13	$4,447,750	$4,280,528	$167,222	0.375	$62,708
10	9	Dec-13	$4,447,750	$4,280,528	$167,222	0.292	$48,773
11	10	Jan-14	$4,447,750	$4,280,528	$167,222	0.208	$34,838
12	11	Feb-14	$4,447,750	$0	$4,447,750	0.125	$555,969
13	12	Mar-14	$4,447,750	$0	$4,447,750	0.042	$185,323
14		Total	$53,373,000	$42,805,284	$10,567,716		1,716,751
15	Ratio						**16.25%**

Column (a) Page 6 Line 1(c)
Column (b) Page 6 Line 2(c)
Coulmn (d)= (12.5- Month No.) / 12

The Narragansett Electric Company
d/b/a National Grid
Inspection and Maintenance Program Summary

Line No.		Fiscal Year 2014	
1	Total Inspection and Maintenance Program	$3,779,000	
	Less:		
2	Electric Contact Voltage expenses included in R.I.P.U.C. Docket No. 4323 - FY 2014	($163,749)	1/
3	Total Inspection and Maintenance Program to be included in FY 2014 Electric ISR	$3,615,251	

1/	Electric Contact Voltage monitoring expenses in R.I.P.U.C. Docket No. 4323		$214,394
	Benefits to be recovered in Pension/OPEB adjustment mechanism		$24,507
	Other Benefits	2/	$26,138
	Contact Voltage monitoring expenses to be excluded from FY 2014 Electric ISR		$163,749

2/ Benefits are not included in the I&M amounts shown on Line 1 and are therefore being adjusted out of the the contact voltage amounts included in base rates.

Section 6

Rate Design

FY 2014 Electric ISR Plan

The Narragansett Electric Company
Infrastructure, Safety & Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors

Line No.		Residential A16 / A60 (a)	Small C&I C-06 (b)	General C&I G-02 (c)	Large Demand B32 (d)	Large Demand G32 (e)	Optional Large Demand B62 (f)	Optional Large Demand G62 (g)	Lighting S10 / S14 (h)	Electric Propulsion X-01 (i)
(1)	O&M Factor per kWh	$0.00190	$0.00213	$0.00146	$0.00090	$0.00090	n/a	n/a	$0.01338	$0.00146
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.57	n/a	$ 0.32	$0.32	n/a	n/a
(3)	CapEx kWh Charge	$0.00000	$0.00000	n/a	n/a	n/a	n/a	n/a	$0.00003	$0.00000
(4)	CapEx kW Charge	n/a	n/a	$0.00	$0.00	$0.00	$0.00	$0.00	n/a	n/a
(5)	Adjusted Base Distribution kW Charge - Back-up Rates	n/a	n/a	n/a	$ 0.19	n/a	$ 0.01	n/a	n/a	n/a

Line No.
(1) Page 3, Line 6; column (d) applicable to supplemental kWh deliveries only
(2) Page 3, Line 8; column (d) per Page 4, column (b), Line 6; column (d) applicable to backup service only
(3) Page 2, Line 6
(4) Page 2, Line 8
(5) Page 4, Line 15

The Narragansett Electric Co.
Proposed CapEx Factors

Line No.		Total (a)	Residential A16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B32 / G32 (e)	Optional Large Demand B62 / G62 (f)	Lighting S10 / S14 (g)	Electric Propulsion X-01 (h)
(1)	Proposed FY2014 Capital Investment under ISR Plan	$42,244							
(2)	Total Rate Base ($000s)	$561,379	$296,303	$54,506	$82,406	$77,601	$19,533	$29,268	$1,762
(3)	Percentage of Total	100.00%	52.78%	9.71%	14.68%	13.82%	3.48%	5.21%	0.31%
(4)	Allocated Proposed Costs to be Recovered	$42,244	$22,297	$4,102	$6,201	$5,840	$1,470	$2,202	$133
(5)	Forecasted kWh - April 2013 through March 2014	7,647,107,645	3,046,523,522	557,335,421	1,279,701,940	2,038,031,800	634,296,460	67,610,668	23,607,834
(6)	Proposed CapEx Factor - kWh charge		$0.00000	$0.00000	n/a	n/a	n/a	$0.00003	$0.00000
(7)	Forecasted kW - April 2013 through March 2014				3,578,998	3,220,070	1,376,851		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$0.00	$0.00	$0.00	n/a	n/a

Line No.
(1) per Section 5: Attachment 1, page 1, line 8, column (c)
(2) per R.I.P.U.C. 4323, Amended Attachment 3A, (Schedule HSG-1-S), page 2, line 10, filed 11/14/12
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per Company forecasts
(6) For non demand-based rate classes, Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) For demand-based rate classes, Line (4) ÷ Line (7), truncated to 2 decimal places
Note: charges apply to kW>10 for rate class G-02 and kW>200 for rate class B32/G32

The Narragansett Electric Co.
Proposed Operations & Maintenance Factors

Line No.		Total (a)	Residential A16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B32 / G32 (e)	Optional Large Demand B62 / G62 (f)	Lighting S10 / S14 (g)	Electric Propulsion X-01 (h)
(1)	FY2014 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,091,251							
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$35,640	$17,115	$3,503	$5,508	$5,438	$1,306	$2,668	$102
(3)	Percentage of Total	100.00%	48.02%	9.83%	15.45%	15.26%	3.66%	7.49%	0.29%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,091,251	$5,806,447	$1,188,430	$1,868,648	$1,844,900	$443,074	$905,147	$34,605
(5)	Forecasted kWh - April 2013 through March 2014	7,647,107,645	3,046,523,522	557,335,421	1,279,701,940	2,038,031,800	634,296,460	67,610,668	23,607,834
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00190	$0.00213	$0.00146	$0.00090	n/a	$0.01338	$0.00146
(7)	Forecasted kW - April 2013 through March 2014						1,376,851		
(8)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		n/a	n/a	n/a	n/a	$0.32	n/a	n/a

Line No.
(1) per Section 5: Attachment 1, page 1, line 3, column (c)
(2) per R.I.P.U.C. 4323, Amended Attachment 3A, (Schedule HSG-1-S), page 4, line 72, filed 11/14/12
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) Line (4) ÷ Line (7), truncated to 2 decimal places

The Narragansett Electric Co.
Calculation of Base Distribution Charge, CapEx and Operations & Maintenance Factors for Back-up Service Rates

Line No.		Total	200 kW Demand B32	3000 kW Demand B62
		(a)	(b)	(c)
	Operations and Maintenance Factor			
(1)	FY2014 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,091,251		
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$35,640	$5,438	$1,306
(3)	Percentage of Total		15.26%	3.66%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense		$1,844,900	$443,074
(5)	Forecasted kW - April 2013 through March 2014		3,220,070	1,376,851
(6)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW		$0.57	$0.32

Adjustment to Base Distribution per kW Charge

		200 kW Demand B32	3000 kW Demand B62
(7)	Base Distribution kW Charge (before 90% discount) per most recent rate case	$ 6.99	$ 3.01
(8)	Proposed O&M kW Factor effective 4/01/2013	$0.57	$0.32
(9)	Proposed CapEx kW Factor Charge effective 4/01/2013	$0.00	$0.00
(10)	Total Undiscounted ISR kW Charges	$0.57	$ 0.32
(11)	Total per kW Charge	$ 7.56	$ 3.33
(12)	Discount Rate applied to Total Distribution kW charge	90%	90%
(13)	Discounted per kW Charge	$ 0.76	$ 0.33
(14)	Sum of Proposed CapEx and O&M per kW Factors	$0.57	$0.32
(15)	Proposed Base Distribution kW Charge for 04/01/2013	$ 0.19	$ 0.01

Line No.
(1) per Section 5: Attachment 1, page 1, line 3, column (c)
(2) from Page 3, line 2
(3) Line (2) ÷ Line (2) Total Column
(4) from Page 2, line 4
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per R.I.P.U.C. 4323 Amended Attachment 3D, (Schedule JAL-4-S), page 5, line 36 and page 6, line 14 filed 11/14/12
(8) Line (6)
(9) from Page 2, Line (8)
(10) Line (8) + Line (9)
(11) Line (7) + Line (10)
(12) per tariff
(13) Line (11) x (1 - Line (12))
(14) Line (10)
(15) Line (13) - Line (14)

Section 7

Bill Impacts

FY 2014 Electric ISR Plan

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$27.83	$11.23	$16.60	$27.88	$11.23	$16.65	$0.05	0.2%	13.7%
300	$49.59	$22.46	$27.13	$49.69	$22.46	$27.23	$0.10	0.2%	17.5%
400	$64.10	$29.95	$34.15	$64.23	$29.95	$34.28	$0.13	0.2%	11.8%
500	$78.61	$37.44	$41.17	$78.77	$37.44	$41.33	$0.16	0.2%	10.8%
600	$93.12	$44.93	$48.19	$93.32	$44.93	$48.39	$0.20	0.2%	9.4%
700	$107.62	$52.41	$55.21	$107.86	$52.42	$55.44	$0.24	0.2%	7.7%
1,000	$151.15	$74.88	$76.27	$151.47	$74.88	$76.59	$0.32	0.2%	15.0%
2,000	$296.22	$149.75	$146.47	$296.86	$149.75	$147.11	$0.64	0.2%	14.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$5.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge (1)	kWh x	$0.03820
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07188

<u>Proposed Rates</u>

Customer Charge		$5.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge (2)	kWh x	$0.03851
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07188

Note (1): includes the current CapEx Factor of 0.000¢/kWh and the current O&M Factor of 0.159¢/kWh

Note (2): includes the proposed CapEx Factor of 0.000¢/kWh and the proposed O&M Factor of 0.190¢/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$20.51	$11.23	$9.28	$20.56	$11.23	$9.33	$0.05	0.2%	10.7%
300	$40.16	$22.46	$17.70	$40.26	$22.46	$17.80	$0.10	0.2%	23.2%
400	$53.26	$29.95	$23.31	$53.39	$29.95	$23.44	$0.13	0.2%	14.9%
500	$66.36	$37.44	$28.92	$66.52	$37.44	$29.08	$0.16	0.2%	12.2%
600	$79.46	$44.93	$34.53	$79.66	$44.93	$34.73	$0.20	0.3%	9.6%
700	$92.55	$52.41	$40.14	$92.78	$52.41	$40.37	$0.23	0.2%	7.3%
1,000	$131.86	$74.88	$56.98	$132.18	$74.88	$57.30	$0.32	0.2%	12.3%
2,000	$262.84	$149.75	$113.09	$263.49	$149.75	$113.74	$0.65	0.2%	9.8%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$0.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge (1)	kWh x	$0.02468
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07188

<u>Proposed Rates</u>

Customer Charge		$0.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01942
Distribution Energy Charge (2)	kWh x	$0.02499
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07188

Note (1): includes the current CapEx Factor of 0.000¢/kWh and the current O&M Factor of 0.159¢/kWh

Note (2): includes the proposed CapEx Factor of 0.000¢/kWh and the proposed O&M Factor of 0.190¢/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
250	$45.96	$18.45	$27.51	$46.08	$18.45	$27.63	$0.12	0.3%	35.2%
500	$80.64	$36.91	$43.73	$80.89	$36.91	$43.98	$0.25	0.3%	17.0%
1,000	$150.00	$73.81	$76.19	$150.49	$73.81	$76.68	$0.49	0.3%	19.0%
1,500	$219.36	$110.72	$108.64	$220.10	$110.72	$109.38	$0.74	0.3%	9.8%
2,000	$288.72	$147.63	$141.09	$289.70	$147.63	$142.07	$0.98	0.3%	19.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$10.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01838
Distribution Energy Charge (1)	kWh x	$0.03416
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

<u>Proposed Rates</u>

Customer Charge		$10.00
LIHEAP Charge		$0.83
Transmission Energy Charge	kWh x	$0.01838
Distribution Energy Charge (2)	kWh x	$0.03463
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Note (1): includes the current CapEx Factor of 0.000¢/kWh and the current O&M Factor of 0.166¢/kWh

Note (2): includes the proposed CapEx Factor of 0.000¢/kWh and the proposed O&M Factor of 0.213¢/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$645.11	$295.25	$349.86	$645.57	$295.25	$350.32	$0.46	0.1%
50	10,000	$1,478.37	$738.13	$740.24	$1,479.52	$738.13	$741.39	$1.15	0.1%
100	20,000	$2,867.11	$1,476.25	$1,390.86	$2,869.41	$1,476.25	$1,393.16	$2.30	0.1%
150	30,000	$4,255.87	$2,214.38	$2,041.49	$4,259.31	$2,214.38	$2,044.93	$3.44	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00594
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00605
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.00135/kWh

Note (2): includes the proposed CapEx Factor of $0.0/kW and the proposed O&M Factor of $0.00146/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$842.87	$442.88	$399.99	$843.56	$442.88	$400.68	$0.69	0.1%
50	15,000	$1,972.74	$1,107.19	$865.55	$1,974.46	$1,107.19	$867.27	$1.72	0.1%
100	30,000	$3,855.87	$2,214.38	$1,641.49	$3,859.31	$2,214.38	$1,644.93	$3.44	0.1%
150	45,000	$5,738.99	$3,321.56	$2,417.43	$5,744.14	$3,321.56	$2,422.58	$5.15	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00594
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00605
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.00135/kWh

Note (2): includes the proposed CapEx Factor of $0.0/kW and the proposed O&M Factor of $0.00146/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$1,040.61	$590.50	$450.11	$1,041.53	$590.50	$451.03	$0.92	0.1%
50	20,000	$2,467.11	$1,476.25	$990.86	$2,469.41	$1,476.25	$993.16	$2.30	0.1%
100	40,000	$4,844.61	$2,952.50	$1,892.11	$4,849.20	$2,952.50	$1,896.70	$4.59	0.1%
150	60,000	$7,222.11	$4,428.75	$2,793.36	$7,228.99	$4,428.75	$2,800.24	$6.88	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00594
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00605
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.00135/kWh

Note (2): includes the proposed CapEx Factor of $0.0/kW and the proposed O&M Factor of $0.00146/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,238.37	$738.13	$500.24	$1,239.52	$738.13	$501.39	$1.15	0.1%
50	25,000	$2,961.49	$1,845.31	$1,116.18	$2,964.35	$1,845.31	$1,119.04	$2.86	0.1%
100	50,000	$5,833.37	$3,690.63	$2,142.74	$5,839.10	$3,690.63	$2,148.47	$5.73	0.1%
150	75,000	$8,705.24	$5,535.94	$3,169.30	$8,713.84	$5,535.94	$3,177.90	$8.60	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00594
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00605
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.00135/kWh

Note (2): includes the proposed CapEx Factor of $0.0/kW and the proposed O&M Factor of $0.00146/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,436.11	$885.75	$550.36	$1,437.49	$885.75	$551.74	$1.38	0.1%
50	30,000	$3,455.87	$2,214.38	$1,241.49	$3,459.31	$2,214.38	$1,244.93	$3.44	0.1%
100	60,000	$6,822.11	$4,428.75	$2,393.36	$6,828.99	$4,428.75	$2,400.24	$6.88	0.1%
150	90,000	$10,188.37	$6,643.13	$3,545.24	$10,198.68	$6,643.13	$3,555.55	$10.31	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (1)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00594
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.70
Transmission Energy Charge	kWh x	$0.00835
Distribution Demand Charge-xcs 10 kW (2)	kW x	$4.98
Distribution Energy Charge	kWh x	$0.00605
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.07086

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.00135/kWh

Note (2): includes the proposed CapEx Factor of $0.0/kW and the proposed O&M Factor of $0.00146/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,659.41	$3,257.92	$2,401.49	$5,666.49	$3,257.92	$2,408.57	$7.08	0.1%
750	150,000	$20,976.91	$12,217.19	$8,759.72	$21,003.47	$12,217.19	$8,786.28	$26.56	0.1%
1,000	200,000	$27,939.40	$16,289.58	$11,649.82	$27,974.82	$16,289.58	$11,685.24	$35.42	0.1%
1,500	300,000	$41,864.41	$24,434.38	$17,430.03	$41,917.54	$24,434.38	$17,483.16	$53.13	0.1%
2,500	500,000	$69,714.41	$40,723.96	$28,990.45	$69,802.95	$40,723.96	$29,078.99	$88.54	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (1)	kW x	$3.70
Distribution Energy Charge (3)	kWh x	$0.00616
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (2)	kW x	$3.70
Distribution Energy Charge (4)	kWh x	$0.00633
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW

Note (2): includes the proposed CapEx Factor of $0.0/kW

Note (3): includes the current O&M Factor of $0.00073/kWh

Note (4): includes the proposed O&M Factor of $0.00090/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$7,754.83	$4,886.88	$2,867.95	$7,765.45	$4,886.88	$2,878.57	$10.62	0.1%
750	225,000	$28,834.72	$18,325.78	$10,508.94	$28,874.56	$18,325.78	$10,548.78	$39.84	0.1%
1,000	300,000	$38,416.49	$24,434.38	$13,982.11	$38,469.62	$24,434.38	$14,035.24	$53.13	0.1%
1,500	450,000	$57,580.03	$36,651.56	$20,928.47	$57,659.72	$36,651.56	$21,008.16	$79.69	0.1%
2,500	750,000	$95,907.12	$61,085.94	$34,821.18	$96,039.93	$61,085.94	$34,953.99	$132.81	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (1)	kW x	$3.70
Distribution Energy Charge (3)	kWh x	$0.00616
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (2)	kW x	$3.70
Distribution Energy Charge (4)	kWh x	$0.00633
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW

Note (2): includes the proposed CapEx Factor of $0.0/kW

Note (3): includes the current O&M Factor of $0.00073/kWh

Note (4): includes the proposed O&M Factor of $0.00090/kWh

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Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$9,850.24	$6,515.83	$3,334.41	$9,864.40	$6,515.83	$3,348.57	$14.16	0.1%
750	300,000	$36,692.54	$24,434.38	$12,258.16	$36,745.66	$24,434.38	$12,311.28	$53.12	0.1%
1,000	400,000	$48,893.58	$32,579.17	$16,314.41	$48,964.41	$32,579.17	$16,385.24	$70.83	0.1%
1,500	600,000	$73,295.66	$48,868.75	$24,426.91	$73,401.91	$48,868.75	$24,533.16	$106.25	0.1%
2,500	1,000,000	$122,099.83	$81,447.92	$40,651.91	$122,276.91	$81,447.92	$40,828.99	$177.08	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (1)	kW x	$3.70
Distribution Energy Charge (3)	kWh x	$0.00616
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (2)	kW x	$3.70
Distribution Energy Charge (4)	kWh x	$0.00633
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW

Note (2): includes the proposed CapEx Factor of $0.0/kW

Note (3): includes the current O&M Factor of $0.00073/kWh

Note (4): includes the proposed O&M Factor of $0.00090/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$11,945.65	$8,144.79	$3,800.86	$11,963.36	$8,144.79	$3,818.57	$17.71	0.1%
750	375,000	$44,550.35	$30,542.97	$14,007.38	$44,616.75	$30,542.97	$14,073.78	$66.40	0.1%
1,000	500,000	$59,370.66	$40,723.96	$18,646.70	$59,459.20	$40,723.96	$18,735.24	$88.54	0.1%
1,500	750,000	$89,011.28	$61,085.94	$27,925.34	$89,144.10	$61,085.94	$28,058.16	$132.82	0.1%
2,500	1,250,000	$148,292.54	$101,809.90	$46,482.64	$148,513.89	$101,809.90	$46,703.99	$221.35	0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (1)	kW x	$3.70
Distribution Energy Charge (3)	kWh x	$0.00616
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

<u>Proposed Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (2)	kW x	$3.70
Distribution Energy Charge (4)	kWh x	$0.00633
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW

Note (2): includes the proposed CapEx Factor of $0.0/kW

Note (3): includes the current O&M Factor of $0.00073/kWh

Note (4): includes the proposed O&M Factor of $0.00090/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$14,041.07	$9,773.75	$4,267.32	$14,062.32	$9,773.75	$4,288.57	$21.25	0.2%
750	450,000	$52,408.15	$36,651.56	$15,756.59	$52,487.84	$36,651.56	$15,836.28	$79.69	0.2%
1,000	600,000	$69,847.74	$48,868.75	$20,978.99	$69,953.99	$48,868.75	$21,085.24	$106.25	0.2%
1,500	900,000	$104,726.91	$73,303.13	$31,423.78	$104,886.29	$73,303.13	$31,583.16	$159.38	0.2%
2,500	1,500,000	$174,485.24	$122,171.88	$52,313.36	$174,750.87	$122,171.88	$52,578.99	$265.63	0.2%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (1)	kW x	$3.70
Distribution Energy Charge (3)	kWh x	$0.00616
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge - > 200 kW (2)	kW x	$3.70
Distribution Energy Charge (4)	kWh x	$0.00633
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW

Note (2): includes the proposed CapEx Factor of $0.0/kW

Note (3): includes the current O&M Factor of $0.00073/kWh

Note (4): includes the proposed O&M Factor of $0.00090/kWh

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Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 200

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	600,000	$96,271.76	$48,868.75	$47,403.01	$96,178.01	$48,868.75	$47,309.26	($93.75)	-0.1%
5,000	1,000,000	$148,646.81	$81,447.92	$67,198.89	$148,490.56	$81,447.92	$67,042.64	($156.25)	-0.1%
7,500	1,500,000	$214,115.61	$122,171.88	$91,943.73	$213,881.23	$122,171.88	$91,709.35	($234.38)	-0.1%
10,000	2,000,000	$279,584.40	$162,895.83	$116,688.57	$279,271.90	$162,895.83	$116,376.07	($312.50)	-0.1%
20,000	4,000,000	$541,459.62	$325,791.67	$215,667.95	$540,834.62	$325,791.67	$215,042.95	($625.00)	-0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (1)	kW x	$3.36
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.33
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.35/kW

Note (2): includes the Proposed CapEx Factor of $0.0/kW and the Proposed O&M Factor of $0.32/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	900,000	$125,740.52	$73,303.13	$52,437.39	$125,646.77	$73,303.13	52,344	($93.75)	-0.1%
5,000	1,500,000	$197,761.39	$122,171.88	$75,589.51	$197,605.14	$122,171.88	75,433	($156.25)	-0.1%
7,500	2,250,000	$287,787.48	$183,257.81	$104,529.67	$287,553.10	$183,257.81	104,295	($234.38)	-0.1%
10,000	3,000,000	$377,813.57	$244,343.75	$133,469.82	$377,501.07	$244,343.75	133,157	($312.50)	-0.1%
20,000	6,000,000	$737,917.95	$488,687.50	$249,230.45	$737,292.95	$488,687.50	248,605	($625.00)	-0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (1)	kW x	$3.36
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.33
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.35/kW

Note (2): includes the Proposed CapEx Factor of $0.0/kW and the Proposed O&M Factor of $0.32/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 400

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,200,000	$155,209.26	$97,737.50	$57,471.76	$155,115.51	$97,737.50	$57,378.01	($93.75)	-0.1%
5,000	2,000,000	$246,875.97	$162,895.83	$83,980.14	$246,719.72	$162,895.83	$83,823.89	($156.25)	-0.1%
7,500	3,000,000	$361,459.35	$244,343.75	$117,115.60	$361,224.98	$244,343.75	$116,881.23	($234.37)	-0.1%
10,000	4,000,000	$476,042.74	$325,791.67	$150,251.07	$475,730.24	$325,791.67	$149,938.57	($312.50)	-0.1%
20,000	8,000,000	$934,376.28	$651,583.33	$282,792.95	$933,751.28	$651,583.33	$282,167.95	($625.00)	-0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (1)	kW x	$3.36
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.33
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.35/kW

Note (2): includes the Proposed CapEx Factor of $0.0/kW and the Proposed O&M Factor of $0.32/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,500,000	$184,678.02	$122,171.88	$62,506.14	$184,584.27	$122,171.88	$62,412.39	($93.75)	-0.1%
5,000	2,500,000	$295,990.55	$203,619.79	$92,370.76	$295,834.30	$203,619.79	$92,214.51	($156.25)	-0.1%
7,500	3,750,000	$435,131.23	$305,429.69	$129,701.54	$434,896.86	$305,429.69	$129,467.17	($234.37)	-0.1%
10,000	5,000,000	$574,271.90	$407,239.58	$167,032.32	$573,959.40	$407,239.58	$166,719.82	($312.50)	-0.1%
20,000	10,000,000	$1,130,834.62	$814,479.17	$316,355.45	$1,130,209.62	$814,479.17	$315,730.45	($625.00)	-0.1%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (1)	kW x	$3.36
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.33
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.35/kW

Note (2): includes the Proposed CapEx Factor of $0.0/kW and the Proposed O&M Factor of $0.32/kW

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Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 600

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,800,000	$214,146.76	$146,606.25	$67,540.51	$214,053.01	$146,606.25	$67,446.76	($93.75)	0.0%
5,000	3,000,000	$345,105.14	$244,343.75	$100,761.39	$344,948.89	$244,343.75	$100,605.14	($156.25)	0.0%
7,500	4,500,000	$508,803.11	$366,515.63	$142,287.48	$508,568.73	$366,515.63	$142,053.10	($234.38)	0.0%
10,000	6,000,000	$672,501.07	$488,687.50	$183,813.57	$672,188.57	$488,687.50	$183,501.07	($312.50)	0.0%
20,000	12,000,000	$1,327,292.95	$977,375.00	$349,917.95	$1,326,667.95	$977,375.00	$349,292.95	($625.00)	0.0%

Present Rates represent the rates which will be in effect as of 2/1/2013 including rates approved in Docket No. 4323 as approved on 12/20/12.

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (1)	kW x	$3.36
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kWh x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.83
Transmission Demand Charge	kW x	$2.92
Transmission Energy Charge	kWh x	$0.00646
Distribution Demand Charge (2)	kW x	$3.33
Distribution Energy Charge	kWh x	($0.00012)
Transition Energy Charge	kWh x	$0.00063
Energy Efficiency Program Charge	kWh x	$0.00895
Renewable Energy Distribution Charge	kW x	$0.00019
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07819

Note (1): includes the current CapEx Factor of $0.0/kW and the current O&M Factor of $0.35/kW

Note (2): includes the Proposed CapEx Factor of $0.0/kW and the Proposed O&M Factor of $0.32/kW

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM R. RICHER

December 28, 2012

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I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is William R. Richer, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am the Director of Revenue Requirements - Rhode Island for National Grid USA Service Company, Inc. ("Service Company"). Service Company provides engineering, financial, administrative, and other technical support to subsidiary companies of National Grid USA. My current duties include revenue requirements oversight for National Grid's electric and gas distribution activities in the U.S., including the electric division of The Narragansett Electric Company d/b/a National Grid ("Narragansett" or the "Company").

Q. Please describe your education and professional experience.

A. In 1985, I earned a Bachelor of Science degree in Accounting from Northeastern University. During my schooling I interned at the public accounting firm Pannell Kerr Forster in Boston, Massachusetts as a staff auditor and continued with this firm after my graduation. In February 1986, I joined Price Waterhouse in Providence, Rhode Island where I worked as a staff auditor and senior auditor. During this time, I earned my certified public accountants license in the State of Rhode Island. In June 1990, I joined National Grid in the Service Company (then known as New England Power Service

Company) as a supervisor of Plant Accounting. Since that time, I have held various positions within the Service Company including Manager of Financial Reporting, Principal Rate Department Analyst, Manager of General Accounting, Director of Accounting Services, and Assistant Controller.

Q. Have you previously filed testimony or testified before the Rhode Island Public Utilities Commission (the "Commission")?

A. Yes. I have testified before the Commission on numerous occasions.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 5 of the Fiscal Year ("FY") 2014 Electric Infrastructure, Safety, and Reliability Plan ("ISR Plan"), which describes the calculation of the Company's revenue requirement for FY 2014 in Attachment 1 of that Section. This revenue requirement is based on the Electric ISR Plan operation and maintenance ("O&M") expenses and capital investment described in the testimony of Ms. Jennifer Grimsley and Mr. Craig Allen.

II. <u>ISR PLAN REVENUE REQUIREMENT</u>

Q. Please summarize the revenue requirement for the Company's FY 2014 Electric ISR Plan.

A. As shown on Page 1, Column (c) of the attachment, the Company's FY 2014 Electric ISR Plan revenue requirement amounts to $12,133,495 and consists of the following elements: (1) operation and maintenance ("O&M") expense associated with the Company's vegetation management ("VM") activities, and the Company's Inspection and Maintenance ("I&M") Program, and (2) the Company's capital investment in electric utility infrastructure. Lines 1 and 2 of that column reflect the forecasted FY 2014 revenue requirement related to O&M expenses for VM and I&M of $8,476,000 and $3,615,251, respectively.

The FY 2014 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $42,244 is shown on Line 8, consisting of the $103,194 revenue requirement on FY 2014 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 2, plus the FY 2014 revenue requirement on incremental non-growth ISR capital investment of $-0- and $(60,950) for FY 2013 and FY 2012 incremental ISR investments, respectively. The total annual FY 2014 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $12,133,495, as reflected in Column (c) on Line 9, and is equal to the sum of Lines 3 and 8.

For illustration purposes only, Column (d) of Page 1 provides the FY 2015 revenue requirement for the respective vintage year capital investments as calculated on

Attachment 1, Pages 2 and 3. Importantly, these amounts will be trued up to actual investment activity after the conclusion of the FY, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

In April 2012, the Company filed an application with the Commission seeking a change in base rates for its electric and gas distribution businesses. The application was assigned Docket No. 4323. The test year used in the Company's request was calendar year 2011. The effective date of new rates in that proceeding is February 1, 2013 for a Rate Year ending January 31, 2014. On October 19, 2012, the Company entered into a settlement agreement with the Division and the U.S. Department of the Navy (the "Navy") and, on November 14, 2012, the Company entered into an amended settlement agreement (the "Amended Settlement Agreement") with the Division and the Navy with regard to the Company's base rate change request. The Commission approved the Amended Settlement Agreement on December 20, 2012. It is important to note that the revenue requirement for the FY 2014 ISR recovery mechanism excludes amounts embedded in base rates in Docket No. 4323 for FY 2012, 2013, and 2014 investments. The calculation of incremental non-growth capital investment is shown on Page 6 of Attachment 1 to Section 5 of the Electric ISR Plan. The amount of vintage year FY 2013 non-growth capital investment in the rate case is equal to the amount of FY 2013 ISR investment so there is no incremental non-growth capital investment for FY 2013, and consequently no incremental revenue requirement for FY 2013 in this proposal. The detailed FY 2014 revenue requirement calculation on incremental non-growth capital investment for vintage years FY 2014 and FY 2012 are shown on Pages 2 and 3 of Attachment 1 to Section 5 of the Electric ISR Plan. A description of this calculation is provided in Section 5 of the Electric ISR Plan.

For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: "nondiscretionary" capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and "discretionary" capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined "nondiscretionary" categories. The amount of capital additions ultimately allowable in the Electric ISR Plan is limited to amounts no greater than the cumulative amount of discretionary project spend as agreed to by the Division and as approved by the Commission. The capital investment amounts on Lines 1 through 3 on Page 6 are broken down further into "nondiscretionary" and "discretionary" categories on Pages 7 through 9.

Tax depreciation used to determine the deferred tax reserve component of rate base has been calculated on Pages 4 and 5 of Attachment 1 for vintage years FY 2014 and FY 2012, respectively, and is described further in Section 5 of the Electric ISR Plan.

Finally, average rate base in the Electric ISR Plan revenue requirement is normally calculated as the average year-end cumulative change in rate base. However, because a portion of FY 2014 non-growth capital investment is reflected in the rate case and the other portion is not, a separate calculation was necessary to apportion the incremental non-growth capital for the year for purposes of determining the weighted average rate base for FY 2014 investment. This calculation is shown on Page 10 of Attachment 1 and is described further in Section 5 of the Electric ISR Plan.

Q. Were there other impacts of the aforementioned rate case Amended Settlement Agreement that affected the FY 2014 Electric ISR Plan revenue requirement?

A. Yes. The FY 2014 Electric ISR Plan revenue requirement has been calculated based upon the agreed to level of embedded depreciation expense and associated composite depreciation rate, effective property tax rate, capital structure, and cost of capital rates (including a 9.50 percent equity return) per the Amended Settlement Agreement. The property tax recovery provisions of the Amended Settlement Agreement have also been incorporated in this revenue requirement proposal as described in Section 5 of the Electric ISR Plan.

Q. Does this conclude your testimony?

A. Yes, it does.

PRE-FILED DIRECT TESTIMONY

OF

NANCY RIBOT

December 28, 2012

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I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is Nancy Ribot, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am a Senior Analyst for Electric Pricing, New England in the Regulation and Pricing group of National Grid USA Service Company, Inc. (the "Service Company"). This department provides rate-related support to The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company").

Q. Please describe your educational background and training.

A. In 2000, I graduated from Fitchburg State University in Fitchburg, MA with a Bachelor of Science Degree in Accounting.

Q. Please describe your professional experience.

A. From 1995 to 1998, I was employed by National Quality Assurance, USA as Junior Accountant. From 1999 to 2000, I held a position as a Cost Accountant at Avery Dennison Corporation. In 2001, I was employed by PriceWaterhouseCoopers as an Associate Auditor. From 2002 to 2007, I was employed as a Senior Accountant at the DCU Center in Worcester, Massachusetts. In 2007, I obtained a position at the Service Company as an accounting analyst for Niagara Mohawk Power Corporation. In 2008, I transferred to the Service Company's New England Electric Pricing Department, and I provide rate-related support to the Company. In 2011, I was promoted to Senior Analyst. My responsibilities include providing support for the Company's filings for its electric service. More specifically, I have prepared the electric pricing schedules pertaining to the Company's 2010, 2011, and 2012 annual retail rate filings, the electric pricing schedules for the fiscal year ("FY") 2012 and FY 2013 Electric Infrastructure Safety and Reliability ("ISR") Plan filings, the Standard Offer Service Quarterly Filings, and the FY 2012 Electric Revenue Decoupling Mechanism Reconciliation filing. In addition, I have provided rate-related support for the Company's two most recent base distribution rate cases, Docket No. 4065 and Docket No. 4323.

Q. Have you previously testified before Rhode Island Public Utilities Commission ("Commission")?

A. Yes. I have testified in reference to the FY 2012 ISR Plan Reconciliation Filing, Docket No. 4218.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) describe the calculation of the ISR factors and of the distribution kW charges applicable to the Back-up Retail Delivery Service proposed in this filing and (2) provide the customer bill impacts of the proposed rate changes.

II. INFRASTRUCTURE, SAFETY AND RELIABILITY PROVISION

Q. Please describe the Company's ISR tariff provision.

A. The Company's ISR Provision, R.I.P.U.C. No. 2118[1], describes the process to establish and implement annual rate adjustments designed to recover the costs associated with the Electric ISR Plan. The tariff consists of two separate mechanisms: 1) an Infrastructure Investment Mechanism ("IIM") designed to recover the costs associated with incremental capital investment; and 2) an Operation and Maintenance Mechanism ("O&MM") designed to recover certain annual Operation and Maintenance ("O&M") expenses pertaining to Inspection and Maintenance ("I&M") and Vegetation Management ("VM") activities.

Infrastructure Investment Mechanism (IIM)

Q. Please describe the operation of the IIM.

A. The IIM provides for the recovery of incremental annual capital investment through CapEx Factors. In conjunction with the filing of the annual Electric ISR Plan by January 1 of each year, the Company will propose CapEx Factors for each rate class designed to recover the cumulative revenue requirement associated with the estimated and actual fiscal year capital investment commencing with the Company's FY ending March 31. The proposed CapEx Factors will be effective for consumption on and after April 1 of each year.

[1] Effective February 1, 2013.

Q. How are the CapEx Factors designed?

A. First, the cumulative revenue requirement approved by the Commission, which will reflect both an estimate of incremental capital investment for the upcoming fiscal year plus the cumulative prior years' actual incremental capital investment, is allocated to each of the Company's rate classes based upon a rate base allocator. The rate base allocator is the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

Next, unit charges for each rate class will be developed from the allocated revenue requirement. For non-demand rate classes, a per kWh charge is calculated by dividing the rate class allocated cumulative revenue requirement by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect. For demand-based rate classes Rate G-02, Rates G-32/B-32, and Rates G-62/B-62, the CapEx Factors are per kW charges and are calculated by dividing the allocated cumulative revenue requirement for each rate class by the forecasted kW billing demand.

Q. Why is the cumulative revenue requirement allocated using a rate base allocator?

A. The cumulative revenue requirement associated with incremental capital investment is allocated in a manner that is similar to the way the revenue requirement on capital investment would be allocated if an allocated cost of service study were to be performed. Since capital investment is primarily related to plant in service, which forms the largest part of rate base, allocating the incremental capital using the most recently approved rate base allocator is an appropriate way to spread the revenue requirement to each of the rate classes.

Q. Are the cumulative revenue requirement, which contains, in part, an estimate of incremental capital investment, and revenue generated from the CapEx Factors subject to reconciliation?

A. Yes. The Company will submit a filing by August 1 of each year ("Reconciliation Filing") in which the Company will propose CapEx Reconciling Factors to become effective for the twelve months beginning October 1. In the Reconciliation Filing, the Company will compare the actual cumulative revenue requirement to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over or under collection of the actual cumulative revenue requirement will be refunded to or collected from customers through the CapEx Reconciling Factors. The amount approved for recovery or refund through the CapEx Reconciling Factors will also be subject to reconciliation with actual amounts billed through the CapEx Reconciling Factors and any difference reflected in future CapEx Reconciling Factors.

<u>Operation and Maintenance Mechanism (O&MM)</u>

Q. Please describe the operation of the O&MM.

A. The O&MM provides for the recovery of O&M budgeted expense associate with the Company's I&M and VM activities. The O&M Factors for each rate class are designed to recover the sum of the annual forecasted I&M expense and forecasted VM expense for the upcoming fiscal year as approved by the Commission in the Company's annual Electric ISR Plan Filing.

Q. How are the O&M Factors designed?

A. To determine the revenue to be collected from each rate class through the O&M Factors, the forecasted I&M and VM expense is allocated to each of the Company's rate classes based upon the O&M allocator derived from allocated distribution O&M expense (i.e., FERC accounts 580-598). This distribution O&M allocator is the percentage of total distribution O&M expense allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

Once the rate class O&M revenue requirement has been determined, per unit rates are developed for each rate class. For Rates G-62/B-62, the O&M Factor is in the form of a demand, or per kW, charge and is calculated by dividing the allocated O&M expense for the combined rate class by the forecasted kW billing demand. For all other rate classes, a per kWh charge is developed by dividing the allocated O&M expense by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect.

Q. Why are the I&M and VM expenses allocated using a distribution O&M allocator?

A. As with the allocation of the revenue requirement on capital investment, the O&M expense is allocated in a manner that is similar to the way these costs would be allocated if an allocated cost of service study were to be performed. Therefore, the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last base rate proceeding is used to spread these costs to each of the rate classes.

Q. Regarding Rates G-02 and B-32/G-32, why are the CapEx Factors designed as demand (per kW) charges and the O&M Factors as per kWh charges?

A. The current distribution charges for Rates G-02 and B-32/G-32 consist of both demand and kWh charges. The designs of the CapEx and O&M Factors for these rate classes are intended to not significantly change the relationship between the existing charges and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts.

Q. Regarding Rate B-62/G-62, why are both the CapEx Factor and the O&M Factor designed as demand (per kW) charges?

A. Presently, the distribution charges for Rate B-62/G-62 consist only of a demand charge and the CapEx and O&M Factors maintain that design.

Q. Are the O&M Factors subject to reconciliation?

A. Yes. In the Company's annual ISR reconciliation filing, the Company will propose an O&M Reconciling Factor to become effective for the twelve months beginning October 1. The Company will compare the actual I&M and VM O&M expense to actual billed revenue generated from the O&M Factors for the applicable reconciliation period, and any over or under collection of actual expense will be refunded to or collected from customers through the O&M Reconciling Factor. The O&M Reconciling Factor will be a uniform per kWh charge applicable to all rate classes. The amount approved for recovery or refund through the O&M Reconciling Factor will be subject to reconciliation with actual amounts billed through the O&M Reconciling Factor and any difference reflected in future O&M Reconciling Factors.

III. PROPOSED FACTORS

CapEx Factors

Q. Please describe the calculation of the proposed CapEx Factors.

A. The CapEx Factors are designed to collect the cumulative revenue requirement related to incremental capital investments through the end of FY 2014. The cumulative revenue requirement of $42,244[2] is developed in the testimony of Company Witness William R. Richer. The cumulative revenue requirement is allocated to the rate classes based on the total rate base allocator, consistent with the provisions of the Amended Settlement Agreement approved by the Commission in Docket No. 4323, and the factors are designed as I have described above using forecasted billing units for the period April 1, 2013 through March 31, 2014. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, Page 2.

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[2] See Section 5: Attachment 1, Page 1, Line 8, Column (c) of the Electric ISR Plan.

<u>O&M Factors</u>

Q. Please describe the calculation of the O&M Factors.

A. The O&M Factors are designed to collect forecasted O&M expense associated with I&M and VM activities for FY 2014. As developed in the testimony of Mr. Richer, these expenses total $12,091,251[3]. The Company has allocated these O&M expenses using an allocator based on distribution O&M from the allocated cost of service study consistent with the provisions of the Amended Settlement Agreement in Docket No. 4323, which the Company believes maintains consistency in how these costs would be reflected in rates, and O&M Factors are designed as I describe above.

<u>Distribution kW Factors applicable to the Back-up Retail Delivery Service</u>

Q. Why is the Company proposing adjustments to the Distribution kW factors applicable to the Back-up Retail Delivery Service?

A. Per R.I.P.U.C. Tariff No. 2132 and 2133, both effective January 1, 2013, the Distribution Charge per kW applicable to Back-up Retail Delivery Service is equal to the base distribution charge per kW charge applicable to Back-up service, as approved in the Company's most recent base rate proceeding, plus the approved Operation and Maintenance and CapEx factors applicable to Back-up Service, both per the Company's approved Infrastructure Safety and Reliability Plan, multiplied by a factor of 10 percent. Becauseince the Company is proposing new O&M and CapEx factors in this filing, the discounted distribution per kW charges applicable to back-up service must be re-calculated to reflect the 90 percent discount on the proposed factors.

[3] See Section 5: Attachment 1, Page 1, Line 3, Column (c) of the Electric ISR Plan.

Q. Please describe the calculation of the proposed Distribution per kW factors applicable to the Back-up Retail Delivery Service.

A. The calculation of the Distribution per kW factors applicable to the Back-up Retail Delivery Service is presented in Section 6, page 4. The sum of the base distribution per kW charge approved in Docket No. 4323, the proposed CapEx Factor and the proposed O&M factor is multiplied by 10%; the product of which represents the *discounted* Back-up Service Distribution per kW charge. The sum of the proposed CapEx and O&M kW charges is then subtracted from the discounted Back-up Service Distribution per kW charge to derive the adjusted base Distribution per kW charge (or credit). In essence, the full discount is reflected in the base Distribution per kW charge.

Q. Is the Company providing a summary of all proposed factors?

A. Yes. The Summary of Proposed Factors is presented in Section 6, page 1.

IV. <u>BILL IMPACTS</u>

Q. Has the Company prepared monthly bill impacts illustrating the effect of the proposed ISR Factors?

A. Yes. The monthly bill impacts for each rate class are shown on Section 7 of the Electric ISR Plan. For the average residential customer using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly rate increase of $0.16 or 0.2 percent based upon rates approved in Docket No. 4323.

V. <u>SUMMARY OF RETAIL DELIVERY RATES</u>

Q. Is the Company including a revised Summary of Retail Delivery Rates tariff, R.I.P.U.C. No. 2095, in its filing?

A. No, the Company is not revising this tariff at this time. The Company will be submitting its annual reconciliation filing in February 2013 proposing additional rate changes for April 1, 2013. Therefore, the Company will submit a compliance filing following the Commission's decision in both the reconciliation filing docket and this docket that will include the Summary of Retail Delivery rates tariff reflecting all of the approved rate changes for April 1, 2013.

VI. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.