The Narragansett Electric Company
d/b/a National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2019 Proposal

December 21, 2017

Docket No. 4783

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter

Raquel J. Webster
Senior Counsel

December 21, 2016

BY HAND DELIVERY AND ELECTRONIC MAIL

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

**RE: National Grid's Proposed FY 2018 Electric Infrastructure, Safety, and Reliability Plan
Docket No. 4783**

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 2019.[2] National Grid has developed this proposed Electric ISR Plan, which is designed to enhance the safety and reliability of the Company's electric distribution system. As required by law, the Company submitted the Plan to the Rhode Island Division of Public Utilities and Carriers (Division) for review. In refining the Plan, the Company received and responded to discovery requests from the Division and consulted with the Division's representatives regarding the Plan. Accordingly, the enclosed Plan reflects a consensus between the Company and the Division.

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 that are driven primarily by condition, maintaining levels of inspection and maintenance, 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 proposed Electric ISR Plan addresses the following budget categories for FY 2019, or the twelve-month fiscal year ending March 31, 2019: capital spending on electric infrastructure projects; operation and maintenance (O&M) expenses for vegetation management (VM); inspection and maintenance (I&M); Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion; and a new proposed Advanced Metering Infrastructure (AMI) pilot program. In addition to the Plan, this filing includes the pre-filed direct testimony of several

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).
[2] The Electric ISR Plan is submitted in compliance with the provisions of R.I. Gen. Laws § 39-1-27.7.1.

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

witnesses. In joint testimony, Prabhjot S. Anand and Ryan A. Moe introduce the Plan and describe its large program components; William R. Richer sponsors the calculation of the Company's fiscal year 2019 revenue requirement under the Plan; and Adam S. Crary describes the calculation of the ISR factors proposed in this filing and provides the customer bill impacts from the proposed rate changes. For a residential customer using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $0.59, or 0.6%.

The enclosed Plan, which the Company is submitting to the PUC for review and approval, presents an opportunity to continue facilitating and encouraging investment in the Company's electric utility infrastructure and enhance the Company's ability to continue providing safe, reliable, and efficient electric service to customers.

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

Very truly yours,

Raquel J. Webster

Enclosures

cc: Steve Scialabba, Division
Greg Booth, Division
Leo Wold, Esq.
Al Contente, Division

Testimony of
Prabhjot S. Anand
& Ryan Moe

JOINT PRE-FILED DIRECT TESTIMONY

OF

PRABHJOT S. ANAND

AND

RYAN A. MOE

December 21, 2017

Table of Contents

I. INTRODUCTION

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

A. My name is Prabhjot S. Anand. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

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

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

A. In 1993, I graduated from Worcester Polytechnic Institute with a Bachelor of Science Degree in Electrical Engineering. In the same year, I was employed by Massachusetts Electric as an Associate Operations Engineer responsible for the design of new distribution facilities for business and capital improvement projects. From 1997 to 2004, I held various roles that involved increasing electric system responsibility relating to the design, implementation, construction, and management of sub-transmission and distribution system projects. In 2004, I received a Master of Science degree in Power Systems Management from Worcester

Polytechnic Institute. In 2004, I was the Manager of Operations Planning and Schedule and responsible for the development and coordination of a regional capital, storm, emergency, and business continuity work plans. From 2008 to 2017, I held various positions and was responsible for the management of complex permitting/high profile projects in the electric transmission and distribution business in New England and upstate New York. I began my current position in February 2017.

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

A. Yes. I have also submitted pre-filed direct testimony in support of the Company's FY 2017 Infrastructure, Safety and Reliability (ISR) Reconciliation filing in Docket No. 4592. In addition, in my previous positions, I have provided operational support for, among other things, the Electric ISR negotiations with the Rhode Island Division of Public Utilities and Carriers (Division).

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

A. My name is Ryan A. Moe. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am employed by the Service Company as a Senior Specialist in Vegetation Strategy. In this role, I am responsible for supporting the design and long-term planning of vegetation strategies used on National Grid USA's distribution and sub-transmission assets. I have also provided support for regulatory reporting in Rhode Island.

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

A. In 2006, I graduated from the University at Buffalo with a bachelor's degree in Environmental Design. In September 2008, I began working for National Grid's Real Estate department. While in the Company's Real Estate department, my responsibilities included mapping the Company's property records along the transmission lines and analyzing vegetation management rights. In February 2012, I began my current position as a Vegetation Specialist.

Q. Have you previously testified before the PUC?

A. Yes. I have testified before the PUC regarding the vegetation management component of the Electric ISR Plan for FY 2015, 2016, 2017, and 2018 in Docket Nos. 4473, 4529, 4592, and 4682 respectively. I have also provided support for Electric ISR reporting since March of 2012.

II. PURPOSE OF JOINT TESTIMONY

Q. What is the purpose of this joint testimony?

A. The purpose of this joint testimony is to present the Electric ISR Plan, which the Company developed as part of a collaborative process with the Division.[1] As is described in the Plan, 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 FY 2019 Electric ISR Plan document is attached as Exhibit 1 to this testimony.

Q. Please summarize the categories of infrastructure, safety, and reliability spending covered by the FY 2019 Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2019, or the twelve-month fiscal year ending March 31, 2019: capital spending on electric infrastructure projects; operation and maintenance (O&M) expenses for vegetation management (VM); inspection and maintenance (I&M); Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion; and the new proposed Advanced Metering Infrastructure (AMI) pilot program.

[1] The Electric ISR Plan presented in this filing is the eighth annual plan submitted to the PUC pursuant to the provisions of R.I. Gen. Laws § 39-1-27.7.1.

Q. Please explain how the FY 2019 Electric ISR Plan is structured.

A. The FY 2019 Electric ISR Plan, which is provided as Exhibit 1 to this testimony, includes the electric infrastructure, safety, and reliability spending plan for FY 2019 and an annual rate reconciliation mechanism that provides for recovery related to capital 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 and O&M expenses for the VM, I&M, VVO/CVR expansion, and AMI pilot programs. After the end of the fiscal year, the Company trues 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 reconciles 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 did the Company prepare the capital investment plan for review by the PUC?

A. The Company prepared the first draft of the Electric ISR Plan, which it submitted to the Division on September 29, 2017 for review. In preparing the capital investment plan, the Company had meetings and discussions with the Division's consultants, Mr. Greg Booth and Ms. Linda Kushner of PowerServices, Inc., regarding the proposed Plan and received and responded to discovery requests from the Division. In this filing, the Company has proposed a capital spending plan for FY 2019 totaling $108.8 million. This proposed capital spending plan includes a range of project work that is required to maintain safe and reliable service. The project work that is included in the FY 2019 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, the Company has provided a detailed explanation of the categories of investment 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 FY 2019 Electric ISR Plan to address 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. Accordingly, the Company has included these categories in the proposed Plan.

Q. Please review the FY 2019 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2019 are associated with five key work categories: (1) Customer Request/Public Requirement (formerly called Statutory/Regulatory); (2) Damage Failure (the Non-Discretionary Spending categories of work); (3) Asset Condition; (4) Non-Infrastructure; and (5) System Capacity and Performance (the Discretionary Spending categories of work). The table below summarizes the proposed spending level for each of these key driver categories proposed for FY 2019.

Proposed FY 2019 Capital Investment by Key Driver Category

Spending Rationale	FY 2019 Proposed Budget	% of Total Capital
Customer Request/Public Requirement	$19,005	17.5%
Damage Failure	$13,674	12.6%
Subtotal Non-Discretionary	$32,679	30.0%
Asset Condition	$26,048	23.9%
Non-Infrastructure	$556	0.5%
System Capacity & Performance	$45,764	42.1%
Subtotal Discretionary (Without South Street)	$72,368	66.5%
Asset Condition - South Street Project	$3,720	3.4%
Subtotal Discretionary	$76,088	70.0%
Total Capital Investment in Systems	**$108,767**	**100%**

As shown in the table above, a significant portion of the investment for capital projects in FY 2019 are necessary to meet regulatory obligations or to comply with various statutes, regulatory requirements or mandates (i.e. $19.0 million or $17.5 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). Overall, the scope and timing of this work is defined by others external to the Company.

The need to repair failed and damaged equipment totals approximately $13.7 million, or 12.6 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 includes the investment necessary to comply with customer/public requirements and to fix damaged or failed equipment. These investments are mandatory and "non-discretionary" in terms of scope and timing. Together, these items account for approximately $32.7 million, or 30.0 percent of proposed capital investment in FY 2019. 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 Company's control, these categories of spending are subject to necessary and unavoidable deviations. As such, mandatory, or non-discretionary, capital investments are 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 2019 have been chosen to maintain the overall reliability of the system and collectively total approximately $76.1 million, or 70.0 percent of the Company's proposed FY 2019 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 load 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 service lives due to thermal stress and to provide appropriate degrees of system configuration flexibility to limit large adverse reliability impacts. 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 investments necessary to improve the overall reliability performance of the network that is realized by the reconfiguration of feeders and the installation of feeder ties. This year, the System Performance and Capacity category includes a new AMI Pilot Program designed to support the objectives of the State's Power Sector Transformation initiative. The specifics of the AMI Pilot Program are discussed in detail in <u>Exhibit 1 of the Plan</u>. System Capacity and Performance projects account for approximately $45.8 million, or 42.1 percent, of the proposed capital investment in FY 2019.

Projects necessary due to the poor condition of infrastructure assets (absent the South Street project) account for approximately $26.0 million or 23.9 percent, of the proposed capital investment in FY 2019. 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 potential reliability issues.

In Docket No. 4592 (Order No. 22471), the PUC directed the Company to manage the South Street budget separate from other discretionary projects in the Plan. For FY 2019, the Company plans to spend approximately $3.7 million or 3.4 percent of its FY 2019 investment on the South Street project.

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 $0.6 million or approximately 0.5% of the capital investment in FY 2019.

Q. Is the Company able to provide a list and detail of the specific projects that will be undertaken in each of the work categories of the FY 2019 Electric Plan?

A. Yes. In the FY 2019 Electric Plan, the Company has provided detail on the specific projects within each work category that would be undertaken in FY 2019 as part of the Electric ISR Plan. The Company and the Division have reviewed these planned projects and the overall spending levels, and have reached consensus regarding the appropriate investment levels for FY 2019.

Q. Throughout the fiscal year, will the Company provide periodic updates regarding the various categories of capital work approved in the FY 2019 Electric ISR Plan?

A. Yes. The Company will provide quarterly reports to the Division and the PUC on the progress of its Electric ISR Plan programs. Additionally, the Company will provide an annual report on the prior fiscal year’s activities when it submits the reconciliation and rate adjustment filings to the PUC. 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. Please describe the FY 2019 spending levels for the Company's VM Program that the Company and Division have identified as appropriate to maintain safe and reliable distribution service to customers.

A. 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. For FY 2019, the Company proposes to spend approximately $9.8 million for the VM Program. This represents a 4.2 percent increase from the $9.4 million which was approved for FY 2018. There are several reasons for this increased spend in FY 2019. First, the Company is scheduled to prune 58 additional miles in FY 2019 compared to FY 2018. Of the 1,328 miles scheduled for pruning in FY 2019, 76 miles were carried over from FY 2018 because of higher than anticipated pruning costs. The Company determined that these circuits could be carried over to FY 2019 without any significant impact to pruning cost or reliability.

V. INSPECTION AND MAINTENANCE PLAN AND OTHER O&M

Q. Please describe the FY 2019 spending levels for the Company's I&M and Other O&M Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service to customers.

A. The FY 2019 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 approximately $0.9 million costs for the I&M program include O&M repairs associated with the capital program, inspections, voltage testing, completion of 20 percent of the Contact Voltage Program ordered in Docket No. 4237. The Other O&M category also includes $25,000 for the on-going long-range system capacity load study, $244,000 for O&M expenses for the Volt/Var expansion program, and approximately $1.1 million for O&M expenses for the AMI pilot program as agreed to with the Division. The Company proposes a total O&M expense budget of approximately $2.2 million for FY 2019.

VI. CONCLUSION

Q. In your opinion does the FY 2019 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 FY 2019 Electric ISR Plan is designed to establish the capital investment, VM, and I&M activities in Rhode Island that are necessary to meet the needs of Rhode Island customers and maintain the overall safety and reliability of the Company's electric distribution system. The Company believes that the proposed Plan accomplishes these objectives. As such, the PUC's approval of the proposed FY 2019 Electric ISR Plan is essential for the Company to continue maintaining a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

The Narragansett Electric Company
d/b/a National Grid

Proposed FY 2019 Electric Infrastructure, Safety, and Reliability Plan
Annual Filing

December 21, 2017

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Section 1
Intro. & Summary

Section 1

Introduction and Summary
FY 2019 Electric ISR Plan Annual Filing

Section 1: Introduction and Summary

Background

National Grid[1] has developed this proposed Fiscal Year 2019 (FY 2019) Electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or Plan) in compliance with Rhode Island's Revenue Decoupling statute, which provides 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 Plan addresses the following categories of costs, as specified in R.I. Gen. Laws § 39-1-27.7.1(d): capital spending on electric infrastructure; operation and maintenance (O&M) expenses on the vegetation management (VM) program; O&M expenses on the inspection and maintenance (I&M) program; and other costs related to maintaining the safety and reliability of the electric distribution system. The Plan also includes O&M I&M costs associated with the Company's Contact Voltage Detection and Repair Program (Contact Voltage Program), mandated by R.I. Gen. Laws § 39-2-25 and approved by the Rhode Island Public Utilities Commission (PUC) in Docket No. 4237.

This Introduction and Summary section presents an overview of the Plan for the above-referenced categories of costs, a description of how the Company proposes to calculate the revenue requirement, a description of how the Company calculated proposed rates, and customer bill impacts.

---

1 The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

2 R.I. Gen. Laws § 39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.

The Plan is the product of a collaborative effort between the Company and the Rhode Island Division of Public Utilities and Carriers (Division). Pursuant to that collaboration, the Company met with the Division on August 31, 2017 to discuss the required pre-filing documentation and presented an overview of the Plan. The Company later submitted the Plan to the Division on September 29, 2017. The Plan is designed to maintain and upgrade the Company's electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, providing for asset viability through targeted investments driven primarily by condition, sustaining levels of I&M, and operating a cost-effective vegetation management program. The Company is submitting this Plan to the PUC for final review and approval.[3]

The Electric ISR Plan provides a description of the Company's proposed electric distribution system safety and reliability activities along with the Company's proposed investments and expenditures contained in the Plan for FY 2019. The Plan itemizes the recommended work activities by general category and provides budgets for capital investment of $108.8 million, which includes $6 million in capital costs for a proposed Advanced Metering Infrastructure (AMI) Pilot Program, and O&M expenses for the VM, I&M, and Other programs which includes additional O&M expense for the AMI Pilot Program.

Consistent with the Revenue Decoupling 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

[3] R.I. Gen. Laws § 39-1-27.7.1 (d) provides that the Company and the Division must work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which the Company must then file with the PUC for its review and approval.

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

As approved in PUC Docket No. 4218, the Company will continue to file quarterly reports with the Division and PUC detailing the progress of its Electric ISR Plan programs. The Company will file the annual report on the prior fiscal year's activities when it submits its reconciliation and rate adjustment filing. 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 annual year-end report.

In Docket No. 4592, the PUC directed the Company to include as part of its FY 2018 Electric ISR Plan filing a proposal to report in quarterly and annual reconciliation filings detail on individual projects where the costs differed from the fiscal year-to-date and fiscal year-end budgets, respectively, by more than ten percent (10%).[4] The Company continues to improve adherence to annual project budgets and schedules, which would reduce the number of projects reported. The Company is focusing on three main areas. First, the Company has implemented process improvements to improve scope definition at project initiation by collecting more information from Operations and other local departments during this phase of the project lifecycle. This information may have otherwise been discovered later in the project lifecycle, resulting in budget variances due to changes to the project scope, estimate, and schedule at that time. Second, the Company has consolidated large project estimating under a single department, which will provide consistent estimating practices when developing Conceptual, Planning, and

[4] Docket No. 4592, Order No. 22471 at pg. 3 (issued on July 11, 2016).

Project Grade estimates. For previous ISR plans, multiple departments were responsible for developing estimates. By applying consistent practices, such as the application of payroll overheads (i.e., benefits, capital clearing accounts, etc.) to direct charges, the variances between the project estimate grades should decline. Third, at the time of the Electric ISR filing, the Company is striving to have Project grade estimates for many, if not all, of the projects that require construction in the upcoming fiscal year. By improving scope definition, cost estimates, and project maturity, the Company believes that the forecasted cash flows used to develop the annual ISR budgets will result in fewer annual budget variances.

The Company continues to make progress with establishing a Long Range Plan for the eleven study areas in Rhode Island. Table 1 below illustrates this progress.

Table 1
National Grid's Study Areas: Current Priority and Statistics

Rank	Study Area	Load (MVA)	% State Load	# of Feeders	# of Stations	Study Status
1	Providence	364	19%	95	17	**100**%
2	East Bay	157	8%	23	7	**100**%
3A	Blackstone Valley North	145	7%	20	5	50%
3B	North Central RI	254	13%	35	10	50%
4	Central RI East	197	10%	38	10	**100**%
5	South County East	184	10%	21	9	85%
6	Central RI West	178	9%	30	11	
7	Newport	136	7%	54	14	
8	Blackstone Valley South	198	10%	60	13	
9	Tiverton	30	2%	4	1	
10	South County West	97	5%	12	6	
	Total:	**1,940**	**100%**	**392**	**103**	**56%**

* Study Status Total = % State Load Weighted Total

The Division has requested that large new infrastructure projects, unless compelled by imminent safety or reliability concerns, should be justified under the Long Range Plan before the

Company includes such projects in the Plan. The Company is advancing projects identified in the recently completed Providence Area Study, particularly the Admiral Street substation rebuild projects.

In summary, the FY 2019 Annual Plan contains $108.8 million of net capital investment, including $6 million for a proposed AMI Pilot Program; plus total O&M costs of $11.9 million. Total O&M costs includes $9.8 million of VM O&M expense, $0.9 million of I&M expense, and $1.3 million of Other O&M expense, of which approximately $1.1 million is associated with the AMI Pilot Program. The remaining sections of this document will address the annual Plan in more detail. Section 2 contains the Company's proposed capital investment plan for FY 2019; Section 3 contains the Company's proposed VM program; Section 4 contains the Company's proposed I&M and Other programs; Section 5 includes a description of how the Company has calculated the FY 2019 Electric ISR Plan revenue requirement; Section 6 includes the calculation of the proposed rates based on the final revenue requirement consistent with the rate design described below; and Section 7 provides the bill impacts associated with the proposed rates. These sections are summarized below.

Section 2: Electric Capital Investment Plan

The Company's proposed electric capital investment plan included 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. Regarding the ratemaking treatment of capital spending, the Company proposes that capital investments used for establishing rates for FY 2019 be those investments in electric distribution infrastructure assets that the Company anticipates will be placed into service during the fiscal year. The amount of capital investment anticipated to be placed into service during FY 2019 is $103.4 million, which includes estimated cost of removal of $12.1 million. The Company has used its capital budget to identify the relevant projects that would be part of the FY 2019 Electric ISR Plan. The capital budget also provides the Company's rationale regarding the need for and benefit of performing that work to provide safe and reliable service to its customers.

Section 3: Vegetation Management

Section 3 of this Plan contains the Company's VM O&M expense for FY 2019, a discussion of the nature of the work the Company expects to perform, and the expected benefits of such work. This proposal provides details of the proposed VM program for FY 2019. This estimated amount is subject to a true-up to actual VM O&M expense in the Company's annual reconciliation filing.

Section 4: Inspection and Maintenance Plan & Other O&M

Section 4 of this proposal contains the Company's I&M O&M expense and Other O&M expenses for FY 2019. This proposal provides details of the proposed I&M program for FY 2019, the O&M expenses associated with the VVO/CVR Expansion, the Long Range Study, and a proposed Advanced Metering Infrastructure (AMI) Pilot program. As with the other projected spending provided in this Plan, this estimated amount will be subject to a true-up to actual I&M expenses and Other O&M expenses in the Company's annual reconciliation filing.

Section 5: Electric Revenue Requirement

Section 5 of this Plan provides a description of how the Company proposes to calculate the revenue requirement based on the projected incremental net infrastructure investment and the total annual VM, I&M, and Other O&M program expenses. 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 approved by the PUC in Docket No. 4323, the Company's last general rate case.

Section 6: Rate Design and Rates

Once the revenue requirement is calculated, it is appropriately allocated to the Company's rate classes. The rate design in this proposal is consistent with the Amended Settlement Agreement in Docket No. 4323, which the PUC approved on December 20, 2012. The rate design and a summary of proposed rates are presented in Section 6. The following will apply for purposes of rate design:

Section 7: Bill Impacts

This section contains the bill impacts associated with the proposed rates.

Section 2
Electric Capital Plan

Section 2

Electric Capital Investment Plan
FY 2019 Electric ISR Plan Annual Filing

Section 2: Electric Capital Investment Plan

Background

The Company[5] developed its proposed Electric ISR 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 asset condition.

A comparison of reliability performance in calendar year (CY) 2016 relative to that of previous years is shown in the charts below. As shown below in Chart 1a, the Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2016, with SAIFI of 0.973 against a target of 1.05, and SAIDI of 69.13 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days. The Company's performance has shown an improving downward trend over the past several years with major event days excluded.

The Plan focuses on the underlying drivers of reliability during the entire year, and including major event days would skew that analysis significantly for the small number of days a

[5] The Company delivers electricity to 491,958 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 6,102 miles of overhead and 1,047 miles of underground distribution and sub-transmission circuit in a network that includes 89 sub-transmission lines and 381 distribution feeders. The Company relies on 67 distribution substations that house 130 power transformers and 871 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 281,775 distribution poles, 4,458 manholes, and 65,749 overhead (pole-mounted) and underground (pad-mounted or in vault) transformers.

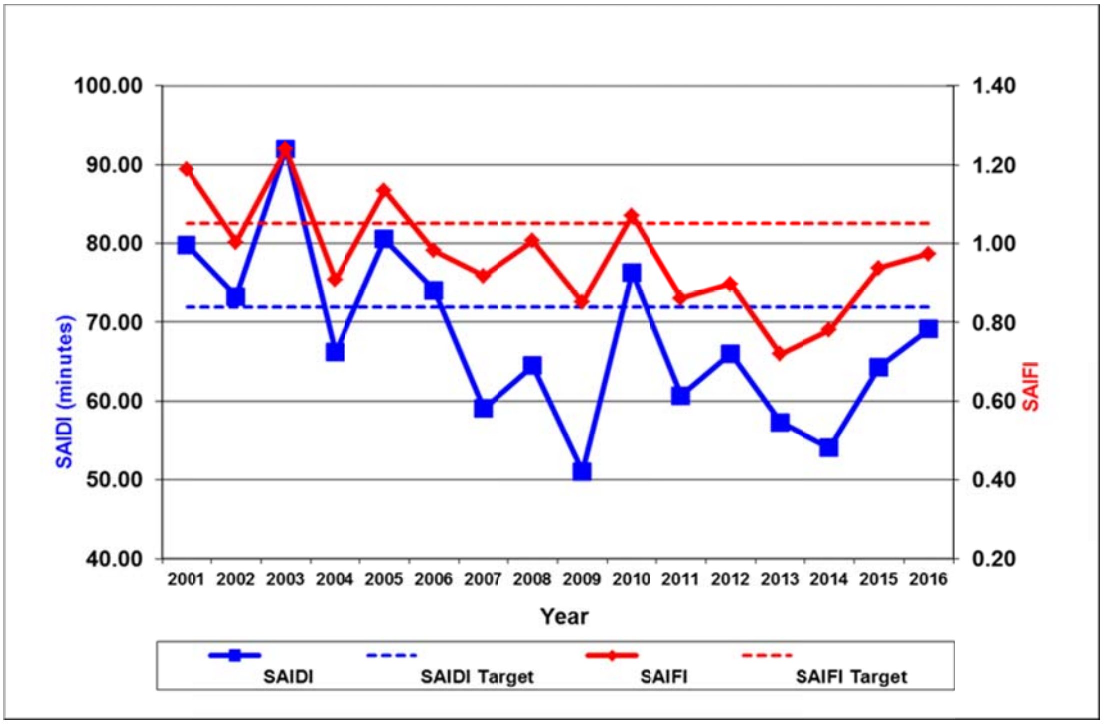
year that are major event days. For example, including major event days would underestimate the day-to-day drivers of reliability due to substation or underground equipment, because, typically, overhead equipment is most impacted by major event days, which are usually weather driven events. In CY 2016, there were four days that were characterized as a major event day. The table below provides additional details including the event, dates, the total number of customers interrupted, and the daily SAIDI performance metric.

CY 2016 Major Event Days

Event	Days Excluded	Total Customers Interrupted	Daily SAIDI
Storm Lexi	2/5/2016	58,233	75.597
Windstorm	2/25/2016	19,683	79.23
Thunderstorm	7/22/2016	15,917	90.509
Storm*	9/5 to 9/6/2016	19,551	NA

* Storm started mid-day 9/5/2016 and carried over to 9/16/2016

Chart 1a
RI Reliability Performance CY 2001 – CY 2016
Regulatory Criteria (Excluding Major Event Days)



For informational purposes, Chart 1b below shows reliability performance from CY 2001 to CY 2016, including major event days.

Chart 1b
RI Reliability Performance CY 2001 – CY 2016
Regulatory Criteria (Including Major Event Days)

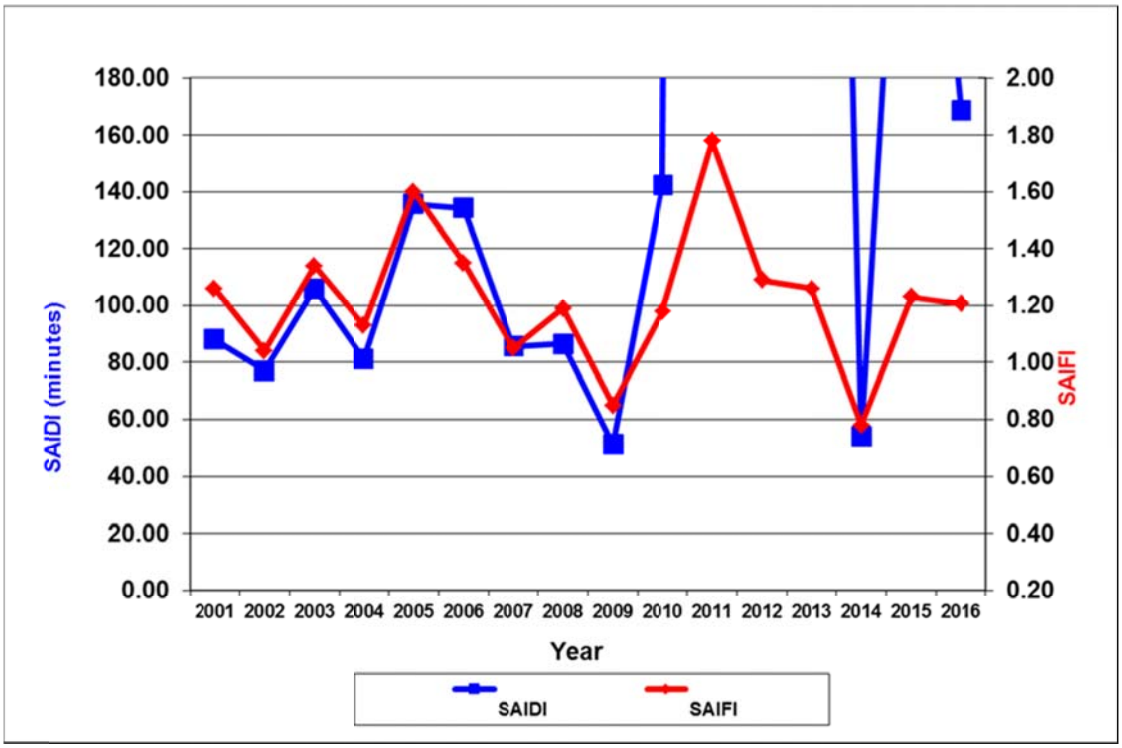


Chart 2 below shows the customers interrupted by cause for CY 2008 through CY 2016. Chart 3 shows the same information in tabular form.

Chart 2
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2016)

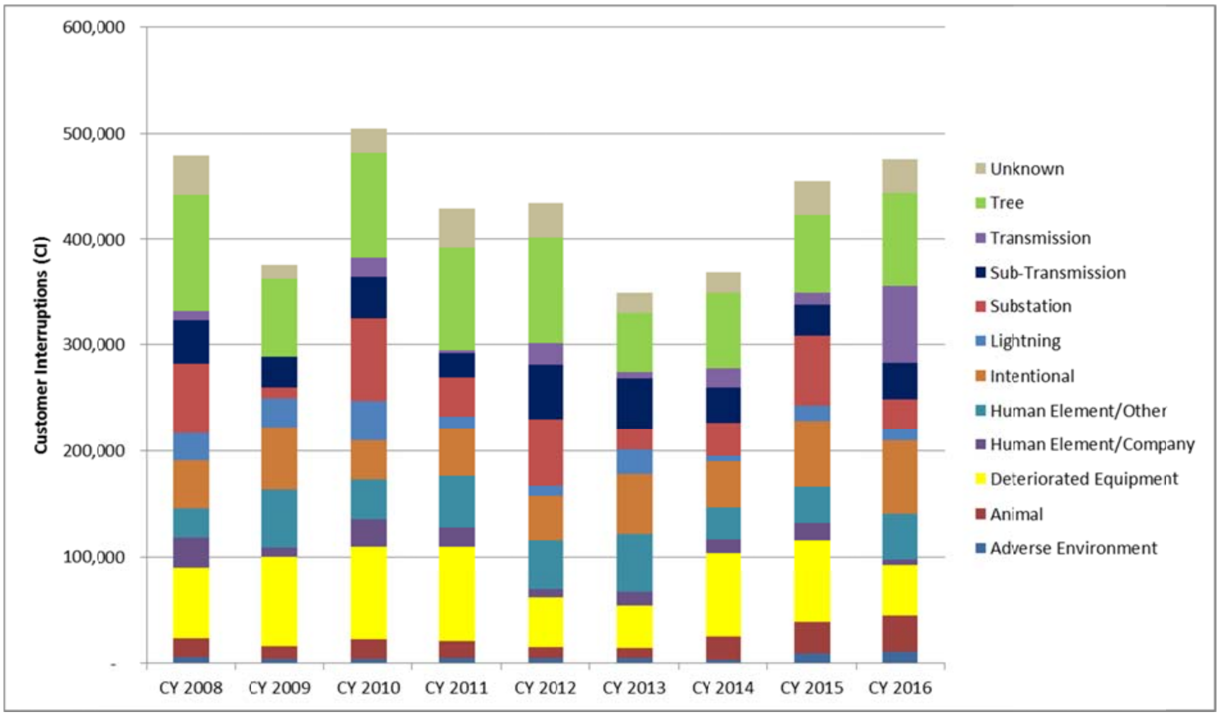


Chart 3
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2016)

Cause	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012	CY 2013	CY 2014	CY 2015	CY 2016
Adverse Environment	5,910	3,926	3,800	4,444	4,778	4,318	3,220	8,677	10,928
Animal	16,977	11,769	18,021	15,547	9,912	10,324	21,247	29,831	33,541
Deteriorated Equipment	67,114	85,047	87,768	89,743	47,301	39,131	79,260	77,575	47,966
Human Element/Company	28,298	8,450	26,047	18,455	7,043	13,481	13,259	16,619	5,489
Human Element/Other	27,607	54,275	36,999	48,650	47,404	54,719	29,908	33,049	43,514
Intentional	44,887	58,356	37,743	44,526	40,927	55,927	43,132	62,373	68,273
Lightning	25,987	27,874	36,859	11,044	9,362	23,310	5,745	14,374	10,832
Substation	65,704	10,713	77,189	37,086	63,397	18,882	30,888	65,932	28,525
Sub-Transmission	40,845	28,046	40,034	22,524	51,972	48,902	33,556	29,211	33,994
Transmission	8,721	25	18,438	2,973	19,099	5,958	18,284	11,594	72,808
Tree	109,214	74,116	97,807	97,485	100,459	55,056	70,277	73,248	87,036
Unknown	37,501	13,545	23,962	36,065	32,176	19,008	19,657	31,703	32,088
Grand Total	**478,765**	**376,142**	**504,667**	**428,542**	**433,830**	**349,016**	**368,433**	**454,186**	**474,994**

Although service quality for the Company is based on a calendar year, capital spending reported in the Electric ISR Plan is based on the Company's fiscal year (April 1 to March 31). Charts 4 and 5 below provide the reliability data as presented in Charts 2 and 3 by fiscal year through FY 2017 (ending March 31, 2017). Chart 5 shows the same information in tabular form.

Chart 4
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2017)

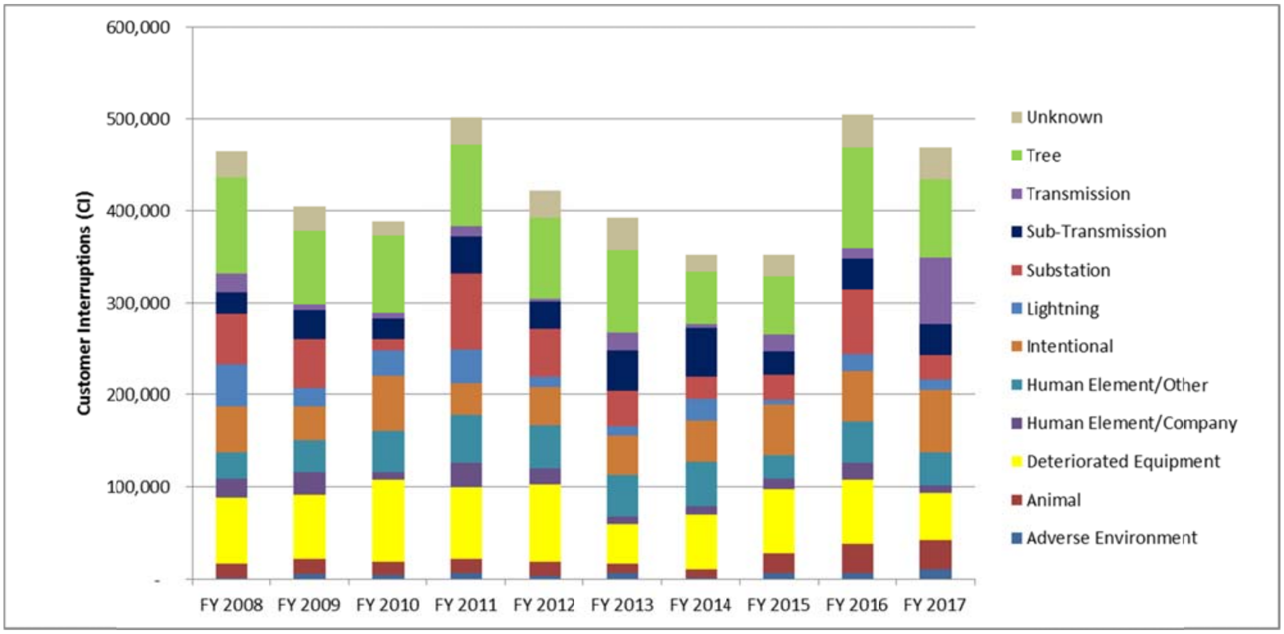


Chart 5
Rhode Island Customer Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2017)

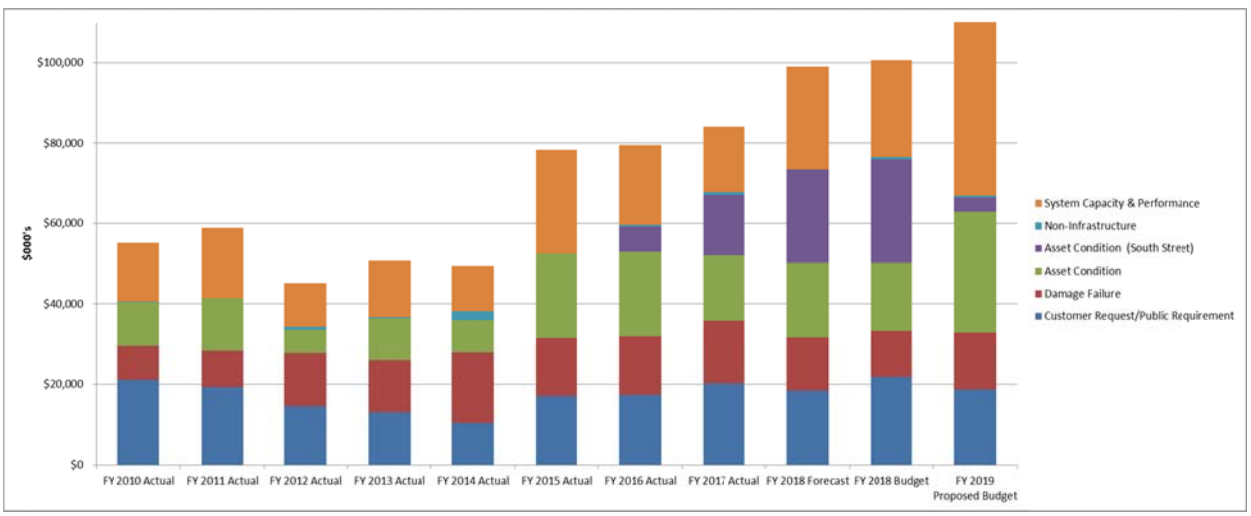
Cause	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
Adverse Environment	1,673	5,651	4,018	5,992	3,674	6,584	811	6,786	5,922	10,108
Animal	15,103	16,303	14,751	15,335	15,008	9,864	10,098	21,232	32,266	31,931
Deteriorated Equipment	71,336	69,296	88,655	78,009	84,052	43,196	59,239	68,992	69,921	50,930
Human Element/Company	20,633	24,393	8,846	27,305	17,722	8,500	9,304	11,507	17,943	8,266
Human Element/Other	28,547	35,531	44,248	51,837	46,171	45,152	48,008	25,659	45,280	36,344
Intentional	50,735	36,569	59,581	33,987	41,879	42,989	44,451	55,268	54,661	67,444
Lightning	44,176	19,577	27,874	36,883	11,098	9,362	23,882	5,234	17,639	11,044
Substation	55,282	53,391	12,120	82,926	51,866	38,492	23,243	26,527	71,115	26,558
Sub-Transmission	24,298	31,628	22,243	39,770	29,805	44,084	53,550	26,191	33,727	33,741
Transmission	20,176	6,000	7,093	11,370	2,973	19,099	4,568	18,284	11,594	72,808
Tree	104,023	79,977	83,311	88,714	88,474	90,726	56,964	63,009	109,023	85,147
Unknown	29,583	26,146	15,807	29,629	29,163	34,143	18,501	23,529	35,829	34,689
Grand Total	**465,565**	**404,462**	**388,547**	**501,757**	**421,885**	**392,191**	**352,619**	**352,218**	**504,920**	**469,010**

Trees, Transmission, Intentional, and Deteriorated Equipment were the top four drivers affecting customers, accounting for 58 percent of all interruptions in FY 2017. It is, therefore, critical that the Company continue to invest in its infrastructure and vegetation management programs to provide reliable electric delivery service to customers.

FY 2019 Capital Investment Plan

As shown in Chart 6 below, the Company plans to invest $108.8 million to maintain the safety and reliability of its electric delivery infrastructure in FY 2019, covering the period from April 1, 2018 through March 31, 2019. Chart 7 shows the same information in tabular form. This spending level is approximately 8 percent higher than the Company's FY 2018 Electric ISR Plan budget of $100.6 million. The increase is primarily driven by the Asset Condition and System Capacity and Performance category, with a decrease in the South Street Substation asset replacement project, as discussed in more detail in Section 2.

Chart 6
Capital Spend by Category FY 2010 – FY 2019



*FY 2018 ISR 1Q Report

Chart 7
Capital Spend by Category FY 2010 – FY 2019
($000)

Spending Rationale	FY 2010 Actual	FY 2011 Actual	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Forecast	FY 2018 Budget	FY 2019 Proposed Budget
Customer Request/Public Requirement	$21,172	$19,312	$14,631	$13,075	$10,410	$17,138	$17,412	$20,233	$16,212	$21,853	$19,005
Damage Failure	$8,345	$9,031	$13,194	$12,993	$17,515	$14,374	$14,531	$15,614	$13,788	$11,379	$13,674
Asset Condition	$10,941	$13,065	$5,831	$10,320	$8,071	$20,905	$20,951	$16,204	$19,171	$16,972	$26,048
Asset Condition (South Street)	$0	$0	$0	$0	$0	$0	$6,228	$15,070	$23,381	$25,772	$3,720
Non-Infrastructure	$151	($847)	$706	$267	$2,269	($346)	$457	$622	($722)	$553	$556
System Capacity & Performance	$14,596	$17,454	$10,795	$13,995	$11,249	$25,972	$19,920	$16,371	$24,641	$24,092	$45,764
Total Capital Investment in Systems	**$55,205**	**$58,015**	**$45,157**	**$50,650**	**$49,514**	**$78,043**	**$79,499**	**$84,114**	**$96,471**	**$100,621**	**$108,767**

*FY 2018 ISR 2Q Report

Since a portion of the proposed capital spending in FY 2019 is for projects that will be completed over multiple years, the Company anticipates that only part of that spending will be placed in service in FY 2019. Likewise, a portion of the capital to be placed in service in FY 2019 will also reflect the capital spending for similar multiyear projects that commenced in prior years. In Docket No. 4592, the PUC directed the Company to provide additional detail in support of the proposed investment for multi-year projects classified as major programs within a category.[6] On August 31, 2017, the Company met with the Division's consultants regarding the proposed FY 2019 Electric ISR Plan spending categories and budgets. During that meeting, the Company provided additional detailed information on major multi-year projects included in the FY 2019 Plan. A summary of information regarding these major multi-year projects is included in Attachment 4. This information varies from previous information the Company provided to

[6] Docket No. 4592, Order No. 22471 (issued July 11, 2016) at page 2.

the Division because the Company continues to refine the project cash flows based on the best information available throughout the development of the Electric ISR Plan.

Chart 8 below provides actual and forecasted Plant-in-Service dating back to FY 2012 (when the Electric ISR Plan was first implemented) through the proposed FY 2019 Plan.

Chart 8
Plant-In-Service FY 2012 – FY 2019

Spending Rationale	Plant-in-Service								
	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Forecast	FY 2018 Budget	FY 2019 Proposed Budget
Customer Request/Public Requirement	$15,144,000	$11,261,897	$13,844,844	$18,443,062	$19,593,559	$14,958,652	$14,049,000	$20,202,000	$17,938,000
Damage Failure	$13,628,000	$12,172,707	$16,928,183	$3,803,602	$16,370,879	$13,635,023	$10,701,000	$12,529,000	$13,053,000
Asset Condition	$13,019,000	$6,638,163	$14,639,889	$28,094,392	$18,532,553	$18,725,716	$37,160,000	$22,199,000	$31,939,000
Non-Infrastructure	$60,000	$112,879	$1,989,798	$345,779	$110,598	$0	$3,000	$0	$494,000
System Capacity & Performance	$9,799,000	$14,145,495	$8,726,837	$25,970,206	$16,845,313	$28,169,947	$14,319,000	$19,913,000	$27,913,000
Total Plant-in-Service	**$51,650,000**	**$44,331,141**	**$56,129,551**	**$76,657,041**	**$71,452,902**	**$75,489,338**	**$76,232,000**	**$74,843,000**	**$91,337,000**

Summary of Investment Plan by Key Driver

Chart 9 below summarizes the planned spending level for each of the key driver categories of the Electric ISR Plan proposed for FY 2019.

Chart 9
Proposed FY 2019 Capital Spending by Key Driver Category
($000)

Spending Rationale	FY 2019 Proposed Budget	% of Total Capital
Customer Request/Public Requirement	$19,005	17.5%
Damage Failure	$13,674	12.6%
Subtotal Non-Discretionary	$32,679	30.0%
Asset Condition	$26,048	23.9%
Non-Infrastructure	$556	0.5%
System Capacity & Performance	$45,764	42.1%
Subtotal Discretionary (Without South Street)	$72,368	66.5%
Asset Condition - South Street Project	$3,720	3.4%
Subtotal Discretionary	$76,088	70.0%
Total Capital Investment in Systems	**$108,767**	**100%**

As shown above in Chart 9, $19.0 million, or 17.5 percent of the spending for capital projects in FY 2019, is necessary to meet customer requests and public requirements. 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 cities and towns and the Rhode Island Department of Transportation (RIDOT). Overall, the scope and timing of this work is defined by those who are external to the Company.

The amounts required to immediately repair failed and damaged equipment totals approximately $13.7 million, or 12.6 percent, of the Company's proposed capital investment in FY 2019. 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 customer requests, statutory and regulatory requirements, and fix damaged or failed equipment as mandatory and non-discretionary in terms of scope and timing. Together, these items total approximately $32.7 million, or 30 percent of the proposed capital investment in FY 2019.

The Company has slightly more discretion regarding 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 2019 have been chosen to minimize the likelihood of reliability issues and other problems due to under investment in the overall system.

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 $45.8 million, or 42.1 percent of the investment dollars categorized as system capacity and performance. 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 service lives due to thermal stress. These types of projects are also designed to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies.

Investments that are required to maintain reliable service to customers accounted for $9.9 million of the system capacity and performance category, or 22 percent of the total proposed category capital budget in FY 2019. This category includes investment to improve the overall performance of the network.

Projects necessary based on the condition of the infrastructure assets account for $29.7 million, or 27.3 percent of the proposed capital spending in FY 2019. Of the $29.7 million, the South Street project accounts for $3.7 million, or approximately 3.4 percent of the proposed capital spending in the Asset category for FY 2019. These projects have been identified to reduce the risk and consequences of unplanned asset failures based on their present condition. The focus of the asset condition 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 and 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. The investments made in these assets are prioritized based on their likelihood 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 above-mentioned 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 $0.6 million, which is 0.5 percent of the proposed capital budget in FY 2019.

The Company considers the investment required to comply with asset condition, non-infrastructure, and system capacity and performance as discretionary in terms of scope and timing. Together, these items total approximately $76.1 million, or 70 percent of the proposed capital investment in FY 2019.

Development of the Annual Work Plan

Each year, the Company develops an Annual Work Plan, which is designed to achieve the Company’s overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. The Annual Work Plan represents a compilation of proposed spending for programs and individual capital projects. Programs and projects are categorized by the following spending categories: Customer Requests/Public Requirements, Damage/Failure, System Capacity and Performance, Non-Infrastructure, and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects and initial estimates for newly proposed projects.

Once the mandatory budget level has been established for the Customer Request/Public Requirements and Damage/Failure spending rationales, the Company reviews programs and projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) for inclusion in the spending plan. A risk score is assigned to each project based upon the estimated probability that a system event will occur and the consequences of the event, 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. Plan inclusion/exclusion for any given project is based on several different factors, including, but not limited to: new project 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. Historical and forward-looking checks are made by spending rationale to identify any deviations from expected or historical trends.

The portfolio is presented to the Company's senior executives, approved by the President of The Narragansett Electric Company, and is ultimately presented 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 for managing the approved budget.

The capital plan for FY 2019 presented in this Plan 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 will soon 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.[7] As previously noted, the Company is striving to have Project grade estimates for many, if not all, of the projects that require construction in the upcoming fiscal year. Increasing the maturity of the projects in the FY 2019 Electric ISR Plan should result in fewer variances to the FY 2019 Electric ISR Plan budget. The Company continuously reviews the capital plan during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, permitting/licensing/agency approvals, system operations, performance, safety, updated estimates, and customer-driven needs that may arise. Based on those changes, the capital plan is updated 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 prior to the start of any work. Approval authority is administered in accordance with the Company's DOA governance policy, with projects over $1.0 million requiring a Project Sanction Paper (PSP). A project sponsor writes the PSP, which includes details regarding many aspects of the project including:

- Project background, description, and drivers
- Business issues and the analysis of alternative courses of action

[7] National Grid defines four levels of estimate grade accuracy: (1) Investment = +200/-50%; (2); Conceptual = +50/-25%; (3) Planning = +25/-25%; and (4) Project = +10/-10%. Each project transitions through these estimate grades as engineering and design are refined.

- Cost analysis of the proposed project
- Project schedule, milestones, and implementation plan

Once an approved project (greater than $1.0 million) is completed, the project manager is responsible for preparing closure papers, which includes 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.

Projects under $1.0 million are authorized online, and the project sponsor must provide relevant information regarding the cost and justification of the proposed project.

Capital projects are authorized for all construction costs following preliminary and final engineering. Reauthorization is required if the Company expects project costs to exceed the approved estimate plus an approved variance range identified in the project spending plan. Any reauthorization request must include the original authorized amount, the variance amount, the reasons for the variance, the details and costs of the variance drivers, and the estimated impact on the current year's spending. On a monthly basis, the project and program management groups monitored project spending against authorized levels. The project and program management groups also review on a monthly basis exception reports covering actual or forecasted project spending greater than authorized amounts.

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 some cases, historical trends are used to develop the appropriate reserve levels, especially reserves related to non-discretionary categories that will address emergent, customer or generator requirements, damaged or failed equipment, or regulatory mandates. The Company manages budgetary reserves and emergent projects within the overall budget as part of its investment planning and current year spending management processes. There are no discretionary reserves in either the proposed FY 2019 plan, or the FY 2020 proposed budget. The discretionary reserves in FY 2021 and beyond will be replaced with specific projects as the Long Term Studies and other tactical initiatives are progressed.

Description of Large Programs and Projects

Attachment 1 to this section provides spending detail on major project categories that support the proposed level of capital spending by key driver shown in Chart 9 above. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available.

Customer Request/Public Requirements

As shown in Attachment 1, the Company has set a budget of $19 million to meet its Customer Request/Public requirements in FY 2019. This is approximately 13 percent lower than the FY 2018 budget of $21.8 million.

Approximately 65 percent of the Customer Request/Public Requirement budget is required to establish electric delivery service to new commercial and residential customers. The Company currently expects to spend approximately $12.3 million for this category of work in FY 2019. Importantly, the actual and proposed spending in this category is net of contributions in aid of construction (CIAC) that are received from customers.

Approximately 13 percent of the Customer Request/Public Requirement budget is required for public projects. The Company currently expects to spend approximately $2.4 million for this category of work in FY 2019. The following projects are included in this category:

- 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

Finally, since much of the construction work in the customer requests and public requirements category is variable and requested on short notice, to account for emergent projects, the Company sets budget reserves for the work under this category based on data from previous fiscal years. Since the Company is reimbursed for a portion of this spending, the budget reserves represent the capital the Company expects to spend, net of CIACs and other reimbursements. Additional information on specific projects for this category is included in Attachment 2.

Damage/Failure

For FY 2019, the Company is proposing a $13.7 million budget for non-discretionary costs to replace equipment that either unexpectedly fails or becomes damaged. This budget is approximately $2.3 million, or 20 percent, higher than the $11.4 million budget for FY 2018, but $1.9 million, or 12 percent, less than the actual Damage/Failure costs incurred by the Company in FY 2017. Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historic trends, which have risen due to increased identification of work identified by local Operations. 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 2019 (e.g., failed substation transformer). As in FY 2018, the budget set for FY 2019 also includes capital spending to address issues that have been identified for immediate repair as part of the I&M program described in Section 4.

There are three major components of the Damage/Failure portion of the Company's capital plan:

- *Damage/Failure Blanket Projects* – These projects are for substation and/or line failures or those assets whose size is unknown at the time of the failure. Currently, the Company expects to spend approximately $11.2 million for this category of work in FY 2019.

- *Damage/Failure Reserve for Specific Projects* – This is 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. Currently, the Company expects to spend approximately $0.9 million for this category of work in FY 2019.

- *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. Currently, the Company expects to spend approximately $1.6 million for this category of work in FY 2019.

Asset Condition

The Company is proposing a $29.8 million budget for FY 2019 to replace assets that must be replaced to maintain reliability performance. This level is approximately 30 percent lower than the $42.7 million budget for FY 2018, and is primarily due to lower spending on the South Street Substation project in FY 2019.

Attachment 3 contains charts illustrating the current age profiles for distribution poles, distribution service transformers, metalclad substations, substation batteries, substation power transformers, and substation breakers and reclosers. Age is not a perfect indicator of asset condition, and, in general, the Company makes asset replacement decisions factoring in asset condition, rather than asset age. Nonetheless, reviewing asset age is a method for demonstrating how current spending levels are improving or maintaining overall asset condition. Attachment 3 also includes charts that detail how current spending levels are expected to improve asset age for metalclad substations and batteries. Unlike other categories of assets, age is used as a primary indicator of asset condition for metal clad substations and batteries. For metalclad substations, continuing with current spending levels for 10 years, the average age of this asset will move from 47 years to 46 years. For substation batteries, continuing with current spending levels for 10 years, the average age of this asset will move from 7 years to 12 years. The Company is currently developing the analysis for other asset categories.

The key asset condition budget categories are as follows:

- *South Street Project* **–** As shown in Attachment 4, the South Street Substation Project is a major 115/11 kV supply substation serving downtown Providence and the surrounding area. The South Street Substation replacement is driven by asset condition concerns. Specific asset condition issues exist for the transformers, breakers, switches, feeder reactors, and the battery system. The building layout precludes the implementation of modern installation standards, which would allow the Company to replace original equipment. Additionally, spare parts for the protection components are obsolete and unavailable. Therefore, these parts would be irreplaceable in the event of a failure. Lastly, maintenance work often requires customized, site-specific repairs, which may be costly and time-consuming. The Company proposes capital spending of approximately $3.7 million on the South Street Project in FY 2019.

- *Southeast Substation* **–** This project is required to address asset condition concerns at the Pawtucket No. 1 substation. The Pawtucket No. 1 substation consists of a four-story brick building that was constructed in 1907 and includes an indoor substation and an outdoor switchyard. In addition to structural issues with the building, the indoor substation includes breakers and relays with condition issues and structures with clearance issues. Electrically, Pawtucket No. 1 station is located on the west side of the Seekonk River and serves half of its load in this area. The other half of the Pawtucket No. 1 load is located on the east side of the river. While the asset conditions indicate the need for a station rebuild of Pawtucket No. 1, the Southeast station site, located on the east side of the river, creates an opportunity to split the load, improve overall capacity, and avoid the capacity and operational constraints created by the river. As shown in Attachment 4, this is a significant multi-year project. At this time, the Company anticipates capital spending in FY 2019 of $2.7 million to progress though final engineering and design, purchase materials, and begin preliminary construction activities.

  Admiral Street – The Providence Area Study identified various asset condition issues within the study area including five indoor substations and over 25 miles of underground cable. The study recommended the expansion of the 12.47 kV distribution system, to enable conversion of the majority of 11.5 kV and 4.16 kV load. This allows the elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations and miles of sub-transmission cable. A large part of the 12.47 kV capacity in the area would be provided by a new 115/12.47 kV station at Admiral Street. The proposed 115/12.47 kV Admiral Street substation would be used to supply the converted load from the Geneva, Harris Avenue, Olneyville, and Rochambeau Avenue substations. The Company is allocating approximately $1.1 million to capture past study costs and continued engineering costs on the Admiral Street Project in FY 2019.

- *Inspection & Maintenance Program* – This program has both capital and O&M components. The proposed capital spending in FY 2019 is $1.7 million. Section 4 includes additional details regarding the capital and O&M components of the I&M program.
- *Strategy to Replace Distribution Substation Batteries* – The Company has more than 117 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 direct current (DC) power for protection, control, and communications within the substation, as well as communication between the substation and the Company's operational control center. One goal of the Company's strategy is to replace batteries that are 20 years or older. Another goal is to ensure that battery systems meet the current operating requirements and perform their designed functions. The Company proposes to spend $0.3 million in FY 2019 to implement this strategy.

- *Dyer Street Replace Indoor Substation* – The purpose of this project is to replace the existing indoor substation at Dyer Street. In FY 2019, the Company proposes capital spending of approximately $1.1 million finalize design, purchase materials and start construction. As shown in Attachment 4, this is another multi-year project with capital spending in future fiscal years.
- The *Substation Metalclad Switchgear Replacement Strategy and Program* **–** This program is another important strategy to improve the reliability of substations. This strategy addresses metalclad switchgears that have known operating issues or are of the same type and manufacturer as equipment that has failed at another location. Solutions typically include replacement of the equipment. In some cases, system configurations allow load to be transferred from these stations in a cost-effective manner, allowing the metalclad equipment to be retired and removed. Presently, there are 44 metalclad switchgear units in Rhode Island operating between 4 kV and 23 kV. Of the 44 units, 28 units were installed prior to 1971. Several design factors with older vintage metalclad switchgear stations contribute to bus and/or component failures. These factors include:
    - *Moisture Sealing Systems* – Moisture and water contribute to most of the metalclad switchgear and buss failures. 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 FY 2019 budget is funded at $2.3 million and includes the retirement of the Lee Street, Cottage Street and Front Street metalclad substations.

- *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 identified 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 switches. The Company expects to address all of its 480V spot networks by FY 2021. The Company expects to spend approximately $0.3 million on this program in FY 2019.
- *Recloser Replacement Strategy and Program* **–** The purpose of this program is to address multiple issues and concerns with the 38 in service Form 3A reclosers in regards to operations, maintenance, safety, reliability, and asset condition. These units have been in service for more than 25 years and are exhibiting a variety of problems, all of which have caused multiple malfunctions, including but not limited to battery charging problems, battery failure, and exterior deterioration/rust. Each location will be individually studied to develop the most cost-effective solution for the replacement, which may require one for one replacement, one for many replacements, relocation, and/or elimination. A coordination analysis of the entire circuit will be reviewed and optimized. The Company

developed a criticality model to prioritize replacements and proposes to spend $0.6 million in capital to replace out of service and the highest priority locations in FY 2019.

- *The Substation Circuit Breaker and Recloser Strategy and Program* **–** This program targets obsolete and unreliable breaker facilities. The Company has approximately 1,038 distribution substation circuit breakers and reclosers in substations that it maintains, refurbishes, and replaces as necessary. The Company has specifically identified units with obsolete technology, such as air magnetic interruption, for replacement. Additionally, where cost-effective and where 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 $0.4 million to implement this strategy in FY 2019.
- *Substation Transformer Replacement Strategy* – This strategy supports the substation transformer asset replacement program, which allows National Grid to rank its substation transformers in terms of health and risk and to identify those transformers that are most critical to the system so that the transformers are properly prioritized for asset replacement. The primary purpose of this strategy is to purchase spare transformers and proactively replace transformers that have a high likelihood of failure due to asset condition issues. The transformers at Lafayette Substation #30 and West Cranston #21 are in the FY 2019 plan. The Company proposes to spend $3.6 million on this strategy in FY 2019.

Underground Cable Strategy **–** The goal of this strategy is to replace primary underground cable that is either in poor condition or has a poor operating history. The

Company's present underground cable replacement program is a combination 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 or similar asset. 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 79F1, 79F2, and 2J8 primary circuits, and portions of the network secondary cable system. In FY 2019, the Company proposes to spend approximately $3.9 million to continue implementing this strategy.

- *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 effected 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 approximately $3.0 million to continue implementing this strategy in FY 2019.

- *Network Blower Motor Program* – This program replaces network vault blower motors with arc resistant motors. Approximately 100 network vault blower motors exist in the Rhode Island electric system predominantly located in Pawtucket and Providence. Approximately 25 motors sites will require additional civil work to increase exhaust ducts and additional wiring work. In FY 2019, the Company proposes to spend approximately $0.25 million to implement this new strategy.

Westerly Rebuild – The Westerly substation was significantly affected from the March 2010 flood and sustained severe damage. All the equipment in the substation yard and inside the control house was damaged. Temporary repairs and temporary equipment replacement were made to restore Westerly to service. This project rebuilds the four existing 15 kV class distribution feeders in a new indoor metalclad configuration on an elevated portion of the site. The project repurposes a former 4 kV building to control costs. This project will also correct area phasing challenges to improve reliability. Rebuilding the Westerly substation was the lowest cost option to mitigate future flood damage risk at that station. The budget for this multi-year project is $0.5 million to progress preliminary engineering in FY 2019.

- *Warwick Mall Flood Restoration* – The 2010 floods resulted in significant equipment damage at Warwick Mall substation. This project elevates control and protection equipment approximately 5 feet above grade, and above flood level and was the lowest cost option to mitigate future flood damage risk at that station. The budget for this project in FY 2019 is $0.6 million.

Blanket Projects – In addition to specific projects, the Company also has asset replacement blanket projects that were 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 historical trends in the volume of work required, input from local Operations, and 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 provide local field engineering and operations with the control accounts to facilitate timely resolution of asset condition issues (i.e., deteriorated equipment). The budget for the substation and distribution line blanket projects in FY 2019 is $2.5 million.

System Capacity and Performance

For FY 2019, the Company is proposing a $45.8 million budget for System Capacity and Performance projects. This increase is driven primarily by the Aquidneck Island Projects, which have a FY 2019 budget of $21.5 million and the introduction of the AMI/VVO pilot program which is described in more detail below. The System Capacity and Performance category includes Load Relief and Reliability projects. The Load Relief projects account for $35.8 million or 78.2 percent of the proposed System Capacity and Performance spending in FY 2019. The remaining 21.8 percent is made up of Reliability projects, which have a proposed FY 2019 spending budget of $9.9 million.

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. The explanatory variables in this model include historical and forecasted economic conditions at the county level,[8] historical peak load data, 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 areas of the state under a normal and extreme weather scenario. The normal weather scenario

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

assumes the same normal peak-producing weather for each year of the forecast. The extreme weather scenario assumes an upper bound peak demand under a given set of economic conditions. Based on the historical experience, there is a 5 percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

The forecast of peak load incorporates the energy efficiency (EE) savings achieved through 2016 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 2016 from the load forecast.

The 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, the Company prioritizes these project proposals and submits them 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 through improved reactive power support.

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. The goal of these guidelines is to develop a combination of wires and non-wires alternatives that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks. As part of this process, the Company conducts analyses at a level of detail commensurate with the scale of the problems and the cost of potential solutions.

Some of the most significant Load Relief Projects for FY 2019 include:

- *Aquidneck Island Projects* – The southern portion of Aquidneck Island is supplied by a highly utilized supply and distribution system. This 23 kV supply system and 4.16 kV distribution system has limited capacity to supply load growth and new spot loads, and it is becoming increasingly challenging to supply large spot loads in southern Middletown and in the City of Newport. The Aquidneck Island Projects proposed budget for FY 2019 is $21.5 million. Below are details on the projects with proposed spending in FY 2019.

  Newport Substation – This project will involve the construction of a new 69/13.8 kV substation and all related distribution line work to develop five new 13.8 kV 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 13.8 kV feeders and conversion of 4 kV load to the new station improves the reliability of the 23 kV supply and 13.8 kV 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. The Company proposes to spend $12.2 million on this project in FY 2019.

- *Jepson Substation* – This project will involve rebuilding the existing substation in Middletown, RI (Jepson Substation). The substation rebuild will include two power transformers supplying six 13.8 kV feeders and two power transformers supplying three 23 kV supply lines. The Company proposes to spend $9.3 million on this project in FY 2019.
- *Proposed Chase Hill Substation (formerly Hopkinton Substation)* **–** This project will involve construction of a new 115/12.47 kV 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 also support retirement of the Ashaway substation. As described in the Asset Condition section, the Chase Hill Substation project alternative analysis has been re-evaluated and the scope has been reduced. The Company proposes to spend approximately $3.9 million on this project in FY 2019.
- *East Providence Substation* – The East Bay Long Term Study identified several asset condition and loading concerns in the East Providence area. The study proposed a new station at the East Providence area that will reduce the loading and dependence on the 23 kV sub-transmission system. This project involves the construction of a new 115/12.47 kV substation in the city of East Providence on a gas company owned land parcel adjacent to the 115 kV transmission right-of-way. Initial construction would consist of a single 40 MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2 MVAR two-stage capacitor bank. The ultimate build-out would be

two 40 MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2 MVAR two-stage capacitor banks. The Company proposes to spend approximately $0.4 million to progress preliminary engineering on this project in FY 2019.

- *Substation EMS/RTU (SCADA) Additions Program* **–** The Company is proposing to expand the EMS/RTU program to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies. The Company proposes to spend approximate $0.6 million for this program in FY 2019.

  Proposed New London Ave Substation (formerly West Warwick Substation) – This project involves the construction of a new 115/12.47 kV 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, with engineering and construction activities to be conducted for the new site. The Company proposes to spend approximately $6.4 million on this project in FY 2019.

- *Flood Contingency Plan* – Climate change prompted a study to identify substations at risk of flooding across all of National Grid’s service territory. This study used Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps (FIRM) to determine whether a substation was within a flood zone, and additional on-site surveys were conducted at locations where potential flooding could occur. As a baseline, the study used the 100-year flood plain (the elevation and regional cover at which there is a 1% probability that flood waters will reach). This was compared to the base elevation of equipment or critical buildings within a substation to determine how deeply equipment or buildings would be submerged during a 100-year flood. Notably, the 100-year flood plain and the FIRM information, is frequently updated by FEMA. Updates typically result in a predicted flood water elevation rise.

Storm term flood hardening solutions will be installed around three substation yards so that main points of entry and egress are still available unless significant flooding is anticipated. The scope of the work will include barriers, pumps, plugs, and generators to displace water inside the substation from general rainfall and leaks in the flood barriers. These solutions are the lowest cost alternatives for this flood hardening work. The FY 2019 budget for this program is approximately $1.0 million, which will be used to progress this work at Warren, Sockanosset, and Westerly Substations.

- *Quonset Substation Expansion* – The Company anticipates that area load growth in the vicinity of the Quonset substation will create normal loading issues and exacerbate contingency loading issues. The Quonset Point Area Study, completed in April 2014, recommends expansion of the existing Quonset Substation to provide the necessary capacity to resolve the projected overload and the load at risk. The comprehensive study identified a number of asset condition issues at the Quonset substation, which the recommended plan will also address. The Company proposes to spend approximately $1.3 million on this project in FY 2019.

Warren 115/12.47 kV Substation – The Warren #5 substation expansion project has been recommended as part of the East Bay Long Term Study. The project expands the existing substation by creating two new 12.47 kV feeder positions, a new substation capacitor, and new distribution construction to provide additional capacity to the Warren and Barrington municipalities. Completion of the project also facilitates the retirement of the Barrington substation, which has safety and asset condition concerns, the capacity constrained Mink 115/23 kV substation, and a significant portion of the 23 kV sub-transmission in the area. The Company proposes to spend approximately $0.5 million to progress preliminary engineering in FY 2019.

Blanket projects – In addition to specific projects, the Company also has three blanket projects that were 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 and reliability reviews, historical trends in the volume of work required, and a forecasted impact of inflation on material and labor rates. The current year spending in the project is monitored on a monthly basis. The substation and line load relief blankets provide O&M services and local field engineering with the control accounts to facilitate timely resolution of system and equipment loading and reliability 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. The reliability blanket also provides local field engineering with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. The budgets for these three blankets total approximately $1.7 million in FY 2019.

- *Volt VAR Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion*: The Company has historically managed the voltage profile of distribution feeders using substation transformer load tap changers, voltage regulators, and capacitor banks with independent, locally based, conservatively programmed controls. Therefore, the Company is generally able to keep the range of voltages provided to customers along the circuit within the required +/- 5 percent ANSI range. This results in a default voltage profile which is high at the substation, and near the low range at the end of line under heavy loads. VVO refers to the process of more intelligently using distribution capacitors and regulators in a coordinated manner to flatten the voltage profile based on real time system performance. Once the profile is flattened, the controller can then lower the voltage coming from the substation to drop the voltage to the entire distribution circuit to be closer to the lower end of the ANSI range. By reducing the service voltage, the mix of loads for those customers will operate more efficiently and use less energy. This effect is called CVR.

  The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralized control of the regulating devices. The Company believes that this will benefit customers by reducing the demand and energy usage through CVR. In FYs 2015, 2016, and 2017, the Company scoped, designed, deployed, and analyzed a small VVO/CVR project area consisting of two substations (Putnam Pike and Tower hill) and seven feeders. Projects completed by other utilities have shown a demand and energy savings of approximately 3 percent and the preliminary results from the pilot show a 3.3 percent demand reduction.

The Company believes that this technology should be further expanded in the Rhode Island service territory. The expansion will leverage the existing back office infrastructure that was installed during the prior small project. The Company will also leverage the lessons learned. The proposal will select areas that have recently undergone a distribution study and have circuit and load characteristics that provide the highest value for the service territory.

To develop an accurate scope of work and budget for this project, the Company leveraged lessons learned and actual costs from the previous small project. The Company used a request for proposal (RFP) process during the pilot, and the Company requested proposals for Advanced Volt/VAR management schemes. The Company selected Utilidata, a Rhode Island based company, as the preferred vendor to provide the necessary integrated control system. This includes distribution, substation, and communications necessary to complete the project based on the Company’s best estimates at this time. In addition, the Volt/Var project will have ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing. In FY 2019, the Company proposes to continue this expansion, with an anticipated spend of approximately $1.9 million in capital, and an accompanying annual O&M cost of $0.2 million, deploying the system on 10 feeders.

- *3V0 Program* – The addition of distributed generators (DG) to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. For certain configurations, additional transmission protection, zero sequence overvoltage or "3V0" protection, is required to prevent the DG from contributing to transmission faults. As DG penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is factor, the duration of the 3V0 work can create unexpected financial impact to the DG development community. Recent legislation with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developmental need, National Grid is developing a proactive 3V0 program, the intent of which is to install 3V0 protective devices in Rhode Island substations on a priority basis. In FY 2019, the Company proposes to spend approximately $0.2 million to implement this program.

  Advanced Metering Infrastructure (AMI) Pilot Program – In its Power Sector Transformation Vision and Implementation Plan (the Plan) (filed in November 2017 as part of Docket 4770), the Company set out proposals for a statewide deployment of advanced metering infrastructure over a 3.5 year period. In setting out its proposal the Company considered advancement of the state's goals laid out in Docket 4600, along with the recommendations of the Division and Office of Energy Resources in the November 2017 Power Sector Transformation report to Governor Raimodo. The resulting proposals laid out in the Plan reflect a balanced approach that seeks to accelerate delivery of customer benefits while managing customer bill impacts.

The Company considers AMI to be a foundational component of a modern grid, essential to enabling customer information, control and choice, but also critical to the utility in efficiently and effectively managing an increasingly complex grid. On the customer side, many of the benefits can be realized upon the introduction of time varying prices; on the grid side, with a communications backbone in place, some benefits can be realized almost immediately on deployment of the meters. Consistent with approach taken by its New York and Massachusetts operating affiliates, the Company is proactively seeking opportunities to accelerate the benefits of AMI where feasible, while learning important and useful lessons that will ultimately improve a full future AMI deployment. With this in mind, the Company is proposing an AMI/VVO pilot program in this Plan. The AMI pilot has been designed to further build on (rather than repeat) the lessons learned through Pilots in Massachusetts and New York, and, importantly, will leverage VVO/CVR investments already contemplated by the state to generate tangible benefits for customers today without stranding investments in the future.

The following sections describe 1) the pilot that is being proposed by the Company in this Plan; 2) the benefits to be gained from the pilot and how these differ from other AMI pilots; and 3) how the pilot advances the goals of Docket 4600.

Overview of the Proposed Pilot

The existing Advanced Meter Reading (AMR) assets in Rhode Island are nearing their average service life of 20 years, with the majority of existing meters having been installed in an AMR deployment program in the period 2000-2001. These AMR meters provide monthly register readings for traditional billing only. Ahead of a full deployment of AMI for all electric and ultimately gas customers in Rhode Island, the Company plans to deploy VVO/CVR functionality on 10 feeders from the Washington and Staples substations serving portions of the towns of Lincoln, Cumberland, and Woonsocket. An associated incremental AMI project is proposed to be deployed in concert with the VVO/CVR project to replace the electric AMR meters for approximately 8,000 customers on Washington's six circuits with a modern AMI meter. In this case, the integration of VVO/CVR with AMI is expected to reduce energy consumption and peak demand by an additional 1 percent on top of the 3 percent already expected from the primary VVO/CVR optimization. The new AMI meters will communicate via a mesh Field Area Network (FAN) that will be designed to support electric meters as well as gas meters and the remote monitoring and control of the primary VVO/CVR devices and any future grid automation. A conceptual review of costs and benefits of this combined AMI/VVO effort were evaluated to be greater than 1 in aggregate. A more detailed assessment is planned as additional design details are determined and a more robust Benefit Cost Model is developed to align with the recommendations of Docket 4600. This detailed assessment as part of the Company's Power Sector Transformation proposal will allow for a fact based decision making around the best communication platform for a broader AMF deployment.

The scope of the proposed AMI pilot includes:

- Replacement of approximately 8,000 AMR meters with AMI meters;
- The creation of a FAN to support proposed AMI meters and VVO grid devices as well as future gas meter integration;
- Establishing a third party backhaul to connect Field Area Network Data with National Grid Business Systems;
- Back office systems integration such as billing of existing tariffed rates and the provision of a daily interval voltage data file for integration with VVO/CVR; and
- Software as a Service (SaaS) supporting back office data collection, meter data management applications, and analytics for voltage analysis.

The Company estimates that the conceptual cost estimate for this work is approximately $6.0 million in capital plus approximately $1.1 million in O&M costs. Of this total, the SaaS costs and communications costs are recurring O&M costs of approximately $0.1 million annually.

Benefits of the Proposed Pilot

There are two types of benefits to be gained from the pilot: monetizable benefits, some of which have been quantified in the benefit cost analysis undertaken for the pilot, and learnings that will support a future AMI deployment for all customers.

- *Energy and Capacity Savings*: Although there are wide-ranging benefits associated with a full scale AMI deployment, the driving benefits being considered in this project are the near term system efficiency benefits associated with enhanced VVO/CVR control. The Company intends for this AMI pilot to provide monetizable benefits in the form of enhanced VVO/CVR energy and capacity savings, such that the pilot achieves a favorable BCA analysis when coupled with base VVO/CVR expansion proposal.
- *Operational Learnings*: Additionally, the Company expects to gain substantial operational learnings with respect to AMI deployment, including the development of a FAN and the integration of distribution system monitoring and control on the same network as AMI meter reading. Having local personnel engaged in the pilot deployment is expected to produce lessons learned with respect to local work practices that will allow the Company to improve the efficiency of a system-wide deployment in the future. With these learnings, the Company can modify existing business processes, maintained within local groups, who will install and maintain the equipment and manage the new data streams. The Pilot will allow Rhode Island-based personnel who have not had the opportunity to incorporate AMI process flow changes that have occurred in Massachusetts or New York to gain an understanding of the technologies and adjust internal functional process flows and work practices. Some examples of these types of learnings are: providing meter installers with outreach and engagement content, training overhead field groups on the installation of the necessary FAN components, properly modifying AMR

van routes due to AMI transitions, and training after-hour trouble-men with new equipment. Notably, this pilot will take advantage of process improvements that were put in place due to other pilots where possible. An example of this is the ability to leverage the centralized call center personnel already trained on AMI equipment.

- Customer Behavior Insights: The deployment of AMI meters will also provide insights into customer behaviors as the Company goes through the process of switching from AMR meters to AMI meters.

- Exploring AMI / modern grid applications and enhancements: As described previously, AMI is a foundational technology which enables a host of modern grid applications. The Company intends to deploy this pilot with the focus of a VVO/CVR implementation, but also to provide a platform to explore additional applications and enhancements. For example, the pilot will provide interval metering data, which would provide the company with enhanced distribution transformer loading information.

- *Outage Management*: The AMI pilot could also be able to provide outage notifications, which could help with restoration efforts. The Company has not quantified or monetized these benefits here; however, these are examples of process improvements that will be investigated by this pilot.

The Company proposes this pilot as a means to further investigate and build on AMF lessons from other pilots. Since the Company is not seeking to repeat the learnings of the AMI pilots undertaken in Massachusetts and New York, there are a number of elements of a traditional AMI deployments that are not being tested here. For example, the Company's affiliate has already piloted Time Varying Rates and customer incentives with the Massachusetts Worcester Smart Energy Solutions Pilot. The Company's affiliate has also investigated additional enhancements, such as a coupled Gas and Electric AMF data, with the Clifton Park New York Demand Reduction Demonstration.

With this pilot, the Company would investigate the integration of AMF data and operational data/control on a common communication network. The lessons learned from all pilots (including this one in Rhode Island), will collectively be valuable to National Grid's operating companies during any statewide roll out of AMI. The benefits of the integration between AMI and VVO have been theoretically modeled in the Company's Power Sector Transformation proposal, and this pilot will help to validate those assumptions.

- *A note on stranded cost mitigation*: There is little risk of stranding the AMI assets being deployed via this pilot because the assets are intended to remain in service until the end of their useful life. In the event that the Company receives approval for a statewide rollout of AMI at a later date, this pilot is designed with future interoperability standards in mind, such as IPv6 and/or Wi-Sun Alliance, allowing alternative vendor devices, networks, or back office systems to seamlessly integrate.

With this interoperability, the pilot meters will expand in functionality to match those proposed by the statewide deployment. If a statewide deployment is not approved, these assets will continue to be utilized without stranding and with the existing suite of functionality.

Advancement of Docket 4600 Goals

The table below details how the AMI pilot would advance the Docket 4600 goals:

Goals for "New" Electric System	Advances? / Detracts from? / Neutral to?
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels).	Advances: Integrating AMI with VVO/CVR is expected to further reduce peak demand and energy consumption, which also further reduces GHG emissions and improves utility's operational efficiency by further reducing technical losses. More accurate, timely customer voltage data could also enable broader (or optimize) deployment of DER.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.	Advances: generates labor income, and helps build a workforce with the skills and experience required to support Rhode Island's future as a clean energy economy.
Address the challenge of climate change and other forms of pollution.	Advances: Integrating AMI with VVO/CVR is expected to further reduce GHG emissions. More accurate, timely customer voltage data could also enable broader (or optimize) deployment of DER over thermal generation alternatives.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits.	Advances: more accurate, timely customer voltage data could enable broader (or optimize) deployment of DER.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.	Advances: more accurate, timely customer voltage data could enable broader (or optimize) deployment of DER.

Goals for "New" Electric System	Advances? / Detracts from? / Neutral to?
Appropriately charge customers for the cost they impose on the grid	Advances: further reducing peak demand and energy consumption and improving utility's operational efficiency could result in lower customer bills
Appropriately compensate the distribution utility for the services it provides.	Advances: more accurate, timely customer voltage data could provide more operational awareness to the utility.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive.	Advances: Integrating AMI with VVO/CVR is expected to further reduce peak demand and energy consumption, which also further reduces GHG emissions and improves utility's operational efficiency by further reducing technical losses. More accurate, timely customer voltage data could also enable broader (or optimize) deployment of DER.

In summary, deploying a small percentage of AMI meters in advance of a full-system deployment would provide important information with respect to the installation and integration of AMI in Rhode Island, test the degree to which system efficiency can be enhanced through the integration of data from the edge of the grid into the VVO/CVR optimization, and allow the evaluation of the potential benefits of new meter applications. Such a pilot has advances the state's Docket 4600 goals and creates no stranding risk.

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 (COR). To develop its Capital Placed-In-Service figure for this filing, the Company used estimated timing of in-service dates for capital spending being placed into service during FY 2019. Each year, as part of the Company's annual reconciliation, the revenue requirement related to discretionary in-service amounts is 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. The discretionary categories include the Asset Condition, Non-Infrastructure, and System Capacity and Performance categories. 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.

Charts 10 below provides details regarding the total FY 2019 proposed amounts for Capital Spending, Plant-in-Service, and COR that have been used in the development of the FY 2019 Electric ISR Plan revenue requirement.

Chart 10

Proposed FY 2019 Proposed Capital Spending, Plant-in-Service, and COR ($000)

Spending Rationale	Proposed Capital Spending FY 2019	Proposed New Capital Placed-in-Service FY 2019	Estimated COR FY2019	New Capital Placed-in-Service + COR
Customer Request/Public Requirement	$19,005	$17,938	$3,078	$21,016
Damage Failure	$13,674	$13,053	$3,350	$16,403
Subtotal Non-Discretionary	$32,679	$30,991	$6,428	$37,419
Asset Condition	$29,768	$31,939	$3,272	$35,211
Non-Infrastructure	$556	$494	$0	$494
System Capacity & Performance	$45,764	$27,913	$2,354	$30,267
Subtotal Discretionary	$76,088	$60,346	$5,626	$65,972
Total Plant-in-Service	**$108,767**	**$91,337**	**$12,054**	**$103,391**

Attachment 1
FY 2019 Capital Spending by Key Driver Category and Budget Classification
($000)

Spending Rationale	Budget Classification	FY 2011 Actual	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Budget	* FY 2018 Forecast	FY 2019 Proposed Budget
Customer Requests/Public Requirements	3rd Party Attachments	($910)	$464	$223	$141	$305	$290	$160	$204	$235	$81
	Distributed Generation	$0	$0	($675)	$195	$0	($933)	$3,760	$1,106	($2,104)	($692)
	Land and Land Rights	$281	$185	$128	$94	$179	$143	$199	$223	$255	$225
	Meters - Dist	$2,215	$1,497	$1,455	$835	$1,824	$2,935	$1,844	$1,786	$1,888	$2,247
	New Business - Commercial	$4,287	$3,391	$3,722	$4,957	$3,924	$7,568	$7,815	$8,183	$6,141	$7,061
	New Business - Residential	$3,530	$2,833	$2,886	$3,593	$2,870	$5,085	$4,598	$5,616	$5,172	$5,247
	Outdoor Lighting - Capital	$411	$495	$488	$758	$533	$129	$144	$154	$200	$123
	Public & Regulatory Requirements	$1,539	$1,135	($1,231)	$4,234	$1,418	$770	($124)	$2,521	$2,365	$2,454
	Transformers & Related Equipment	$3,278	$3,075	$3,415	$2,331	$3,634	$1,425	$1,837	$2,060	$2,060	$2,259
Customer Requests/Public Requirements Total		**$14,631**	**$13,075**	**$10,410**	**$17,138**	**$14,687**	**$17,412**	**$20,233**	**$21,853**	**$16,212**	**$19,005**
Damage/Failure	Damage/Failure	$8,331	$9,574	$7,795	$11,228	$8,816	$11,327	$13,594	$9,828	$12,415	$12,074
	Major Storms - Dist	$4,863	$3,419	$9,720	$3,146	$1,000	$3,204	$2,020	$1,550	$1,373	$1,600
Damage/Failure Total		**$13,194**	**$12,993**	**$17,515**	**$14,374**	**$9,816**	**$14,531**	**$15,614**	**$11,378**	**$13,788**	**$13,674**
Asset Condition	Asset Replacement	$5,604	$9,767	$6,984	$14,011	$11,807	$16,031	$12,339	$14,955	$17,218	$24,047
	Asset Replacement - South Street	$0	$0	$0	$0	$0	$6,228	$15,070	$25,773	$23,381	$3,720
	Asset Replacement - I&M (NE)	$227	$553	$1,086	$6,681	$7,040	$4,811	$3,022	$1,600	$1,509	$1,700
	Safety & Other	$0	$0	$0	$213	$514	$110	$844	$417	$444	$300
Asset Condition Total		**$5,831**	**$10,320**	**$8,070**	**$20,905**	**$19,361**	**$27,179**	**$31,274**	**$42,745**	**$42,552**	**$29,767**
Non-Infrastructure	Corporate/Admin/General/Other	$645	$118	$890	($1,245)	$0	($61)	$86	$0	($1,132)	$0
	General Equipment - Dist	$61	$149	$191	$395	$102	$331	$383	$378	$247	$306
	Telecommunications Capital - Dist	$0	$0	$1,188	$504	$175	$187	$153	$175	$163	$250
Non-Infrastructure Total		**$706**	**$267**	**$2,269**	**($346)**	**$277**	**$457**	**$622**	**$553**	**($722)**	**$556**
System Capacity & Performance	Load Relief	$6,012	$8,837	$6,619	$22,762	$19,052	$16,491	$13,800	$21,079	$20,235	$35,849
	Reliability	$2,799	$2,554	$3,723	$3,210	$2,707	$3,429	$2,571	$3,012	$4,406	$9,916
	Reliability - Feeder Hardening	$1,984	$2,564	$907	$0	$0	$0	$0	$0	$0	$0
System Capacity & Performance Total		**$10,795**	**$13,955**	**$11,249**	**$25,972**	**$21,759**	**$19,920**	**$16,371**	**$24,091**	**$24,641**	**$45,765**
Grand Total		**$45,157**	**$50,610**	**$49,514**	**$78,043**	**$65,900**	**$79,499**	**$84,114**	**$100,620**	**$96,471**	**$108,767**

*As submitted in Q2 FY2018 ISR Report

Attachment 2
FY 2019 Project Detail for Capital Spending
($000)

Spending Rationale	Budget Class Codes	Project #	Project Description	FY2019 Capital Budget ($000)
Customer Request/Public Requirement	**3rd Party Attachments**	COS0022	OCEAN ST-DIST-3RD PARTY ATTCH BLNKT	81
	Distributed Generation	C051909	PS&I DIST GEN RI.	(1,000)
		C078177	22931079-S-GRNDEV-	60
		C078506	21069530-S-S.SKY-WARWICK-KILVERTST	49
		C078574	21051365/21051371-S-COMPASSCIRCLE	199
	Land and Land Rights	COS0091	LAND AND LAND RIGHTS RI ELECT	225
	Meters - Dist	CN04904	NARRAGANSETT METER PURCHASES	1,530
		COS0004	OCEAN ST-DIST-METER BLANKET	717
	New Business - Commercial	C046977	RESERVE FOR NEW BUSINESS COMMERCIAL	2,810
		C051203	LNG PLANT SVC TERMINAL RD PRV DLINE	100
		C051204	LNG PLANT SVC TERMINAL RD PRV DSUB	48
		COS0011	OCEAN ST-DIST-NEW BUS-COMM BLANKET.	4,103
	New Business - Residential	C046978	RESERVE FOR NEW BUSINESS RESIDENTIA	335
		COS0010	OCEAN ST-DIST-NEW BUS-RESID BLANKT	4,912
	Outdoor Lighting - Capital	COS0012	OCEAN ST-DIST-ST LIGHT BLANKET.	123
	Public Requirements	C046970	RESERVE FOR PUBLIC REQUIREMENTS UNI	941
		C050687	DOTR-HI HAZ INT/RAMPS C2 NEWPORT CO	84
		C050921	DOTR-HI HAZ INTERSECTIONSBRISTOL CO	84
		C054787	DOTR-RICHMOND: KINGSTON RD BR 403	77
		C054828	DOTR-ARTERIAL IMPR TO WARWICK AV	15
		C057779	DOTR-COVENTRY:FLATRIVERRD@VICTORYHW	71
		C059639	DOTR-PROV:VIADUCT BR NB-SMITH ST BR	85
		C075202	RELOC 4 FEEDERS ROGER WILLIAMS WAY	50
		CD00567	DOTR-EAST MAIN RD, TURNPIKE AV-HEDL	79
		COS0013	OCEAN ST-DIST-PUBLIC REQUIRE BLNKT	967
	Transformers & Related Equipment	CN04920	NARRAGANSETT TRANSFORMER PURCHASES	2,259
Customer Request/Public Requirement Total				**19,005**
Damage/Failure	**Damage/Failure**	C046986	RESERVE FOR DAMAGE/FAILURE UNIDENTI	105
		C051608	RESERVE FOR DAMAGE/FAILURE SUBSTATI	780
		COS0002	OCEAN ST-DIST-SUBS BLANKET.	744
		COS0014	OCEAN ST-DIST-DAMAGE&FAILURE BLNKT	10,445
	Major Storms - Dist	C022433	OSD STORM CAP CONFIRM PROGRAM PROJ	1,600
Damage/Failure Total				**13,674**

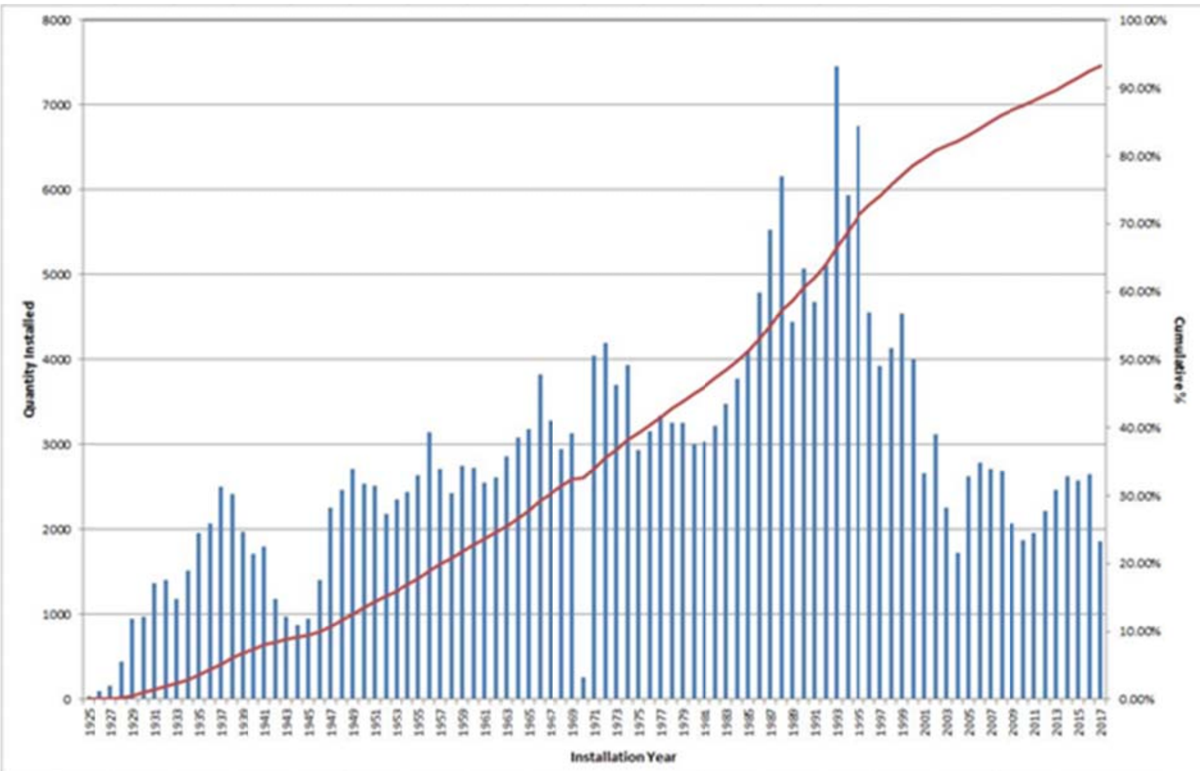
Non-Infrastructure	**General Equipment - Dist**	COS0006	OCEAN ST-DIST-GENL EQUIP BLANKET	306
	Telecommunications Capital - Dist	C040644	TELECOM SMALL CAPITAL WORK - RI	250
Non-Infrastructure Total				**556**
Asset Condition	**Asset Replacement**	C025815	OS ARP INSUL, SENSDEV, SURGE ARREST	250
		C032019	BATTS/CHARGERS NE SOUTH OS RI	300
		C032278	OS ARP BREAKERS & RECLOSERS	325
		C036527	WESTERLY FLOOD RESTORATION (D-SUB)	416
		C047379	IRURD WOOD ESTATES PH II	233
		C047398	IRURD WIONKHEIGE	1,661
		C048969	RI RAPR ARP	195
		C050070	IRURD PLACEHOLDER RI	100
		C050758	LEE ST MC RETIREMENT (D-LINE)	1,000
		C050760	COTTAGE ST MC RETIREMENT (D-LINE)	1,000
		C050778	FRONT ST SUB MC RETIREMENT (D-LINE)	298
		C051118	LEE ST MC RETIREMENT (D-SUB)	-
		C051126	COTTAGE ST MC RETIREMENT (D-SUB)	-
		C051205	DYER ST REPLACE INDOOR SUBST D-SUB	830
		C051211	DYER ST REPLACE INDOOR SUBST D-LINE	294
		C051273	FRONT ST METALCLAD-SUB RETIREMENT	-
		C051274	DAGGETT AVE MC RETIREMENT (D-SUB)	-
		C051824	LAFAYETTE SUB TRANSFORMER REPLACEME	1,150
		C053657	SOUTHEAST SUBSTATION (D-SUB)	1,400
		C053658	SOUTHEAST SUBSTATION (D-LINE)	1,300
		C053723	ARCTIC SUBSTATION RETIREMENT	-
		C054365	63 LINE IMPROVEMENTS	108
		C055215	WESTERLY FLOOD RESTORATION (D-LINE)	120
		C055359	RI UG CABLE REPL PROGRAM - FDR 79F1	342
		C055360	RI UG CABLE REPL PROGRAM - FDR 2J8	583
		C055362	RI UG CABLE REPL PROGRAM - FDR 1105	36
		C055364	RI UG CABLE REPL PROGRAM - FDR 13F6	434
		C055365	RI UG CABLE REPL PROGRAM - FDR 1113	25
		C055370	RI UG CABLE REPL PROGRAM FDR 1144	25
		C055371	RI UG CABLE REPL PROGRAM FDR 1142	301

		C055392	RI UG CABLE REPL PROGRAM - SECONDAR	1,094
		C055683	PAWTUCKET NO 1 (D-SUB)	-
		C055844	W CRANSTON TRANSFORMER 2 REPLACEME	2,400
		C056947	IRURD JUNIPER HILLS WWARWICK	359
		C057921	IRURD-ROBIN HILLS ESTATES	150
		C058042	IRURD-BROOKRIDGE ESTATES.	350
		C069166	PAWTUCKET 1 BREAKER REPLACEMENT	50
		C069206	AUBURN 73 BREAKER REPLACEMENTS	50
		C069506	IRURD NORTH FARM URD	63
		C070207	IRURD EVERGREEN APTS URD E. PROVID	85
		C071307	RI UG CABLE REPL PROG- FDRS 79F1&F2	526
		C072826	RI UG CABLE REPL PROGRAM - FDR 1104	105
		C072847	RI UG CABLE REPL PROGRAM - FDR 1106	179
		C074307	RI UG 79F1 DUCT CHARLES & ORMS STS	250
		C074804	APPONAUG 23KV RETIREMENTS (D-SUB)	151
		C074807	APPONAUG 23KV RETIREMENTS (D-LINE)	36
		C075445	RI ROYAL DISCONNECT REPLACEMENT	205
		C077365	CLARKSON ST 13F10 - HAWKINS ST	140
		C077368	OLNEYVILLE 6J5 FEEDER RETIREMENT	150
		C078474	FRANKLIN SQ SUB_1105 & 1109 NW	250
		C078476	HOPE SUB POLE REPLACEMENT	234
		C078734	ProvStudy Admiral St 4&11kV Convert	110
		C078735	ProvStudy New Admiral St 12kV D-Sub	140
		C078797	ProvStudy Admiral St-Rochamb D-Sub	45
		C078802	ProvStudy Olneyville 4kV D-Line	55
		C078803	ProvStudy Admiral St 12kV MH&Duct	80
		C078804	ProvStudy Admiral St 12kV Cables	60
		C078805	ProvStudy Knightsville 4kV Convert	135
		C078810	ProvStudy HarrisAve 11kV(1129&1137)	45
		C078811	ProvStudy Geneva,Olnyvile,Rocham4kV	275
		C078857	ProvStudy Harris Ave 4&11kV Retire	170
		CD01097	WARWICK MALL SUBSTATION FLOOD RESTO	580
		COS0017	OCEAN ST-DIST-ASSET REPLACE BLANKT	2,353
		COS0026	OS-DIST-SUBSTATION ASSET REPL BLNK	153
		C079183	RI Repl ACNW Vlt Vent Blowers FY19	250
		C078997	IR-URD P5, APOLLO ST, WARWICK, RI	-
		C078488	RI DFP100 RELAY REPLACEMENT PROJECT	46
	Asset Replacement - I&M (NE)	C026281	I&M - OS D-LINE OH WORK FROM INSP.	1,700
	Safety	CD01257	DISTRIBUTION SECONDARY NETWORK ARC	300
Asset Condition Total				**26,048**
Asset Condition - South St	**Asset Replacement**	C051212	SOUTH ST REPL INDOOR SUBST D-SUB	2,100
		C051213	SOUTH ST REPL INDOOR SUBST D-LINE	1,620
		C055623	SOUTH ST SUB 11KV REMOVAL	-
Asset Condition - South St Total				**3,720**

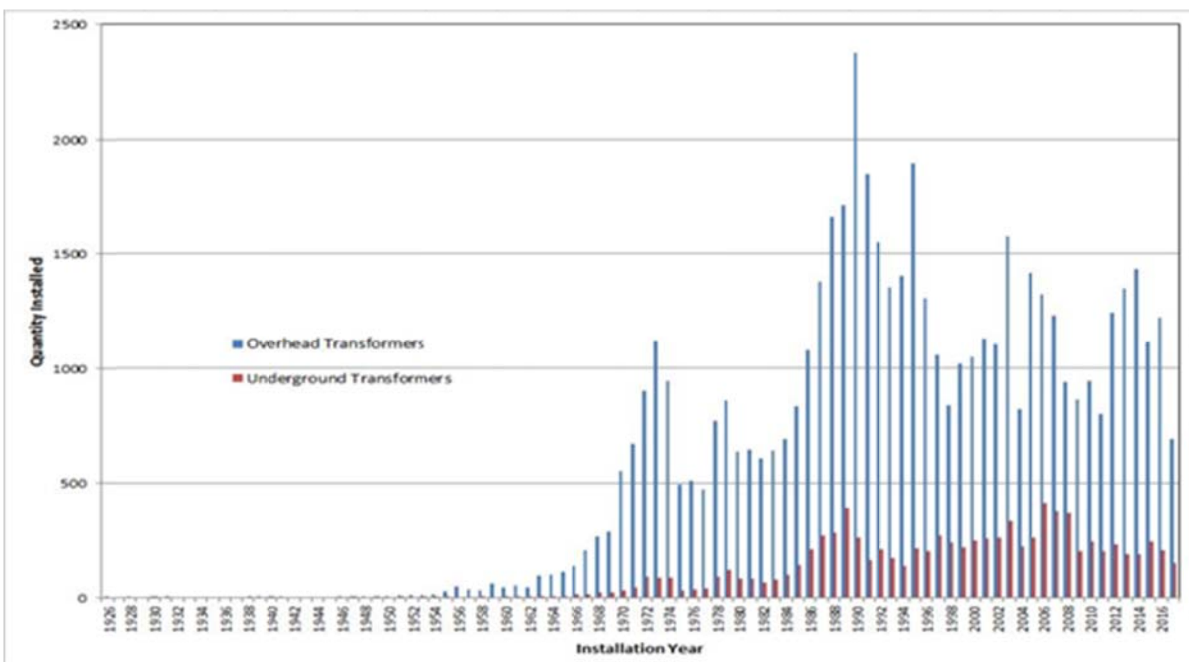
System Capacity & Performance	**Load Relief**	C005505	IE - OS DIST TRANSFORMER UPGRADES	550
		C013967	PS&I ACTIVITY - RHODE ISLAND	(897)
		C015158	NEWPORT SUBSTATION (D-SUB)	5,762
		C024159	NEWPORT 69KV LINE 63 (D-LINE)	1,219
		C024175	CHASE HILL SUB (D_LINE)	3,900
		C028628	NEWPORT SUBTRANS & DIST CONVERSION	5,179
		C028920	NEW LONDON AVE (D-SUB)	4,516
		C028921	NEW LONDON AVE (D-LINE)	1,900
		C034102	RETIRE ASHAWAY 43 SUBSTATION	-
		C036233	HOPE VALLEY (D_SUB)	-
		C036234	HOPE VALLEY (D_LINE)	-
		C046352	VOLT VAR DLINE RI PILOT PROJECT	1,900
		C046726	EAST PROVIDENCE SUBSTATION (D-SUB)	200
		C046727	EAST PROVIDENCE SUBSTATION (D-LINE)	200
		C053646	QUONSET SUB EXPANSION (D-SUB)	595
		C053647	QUONSET SUB EXPANSION (D-LINE)	693
		C054054	JEPSON SUBSTATION (D-LINE)	484
		C065166	WARREN SUB EXPANSION (D-SUB)	220
		C065187	WARREN SUB EXPANSION (D-LINE)	230
		CD00649	GATE 2 SUBSTATION (D-SUB)	90
		CD00656	JEPSON SUBSTATION (D-SUB)	8,800
		COS0016	OCEAN ST-DIST-LOAD RELIEF BLANKET.	307
	Reliability	C049679	HARRISON 32 - EMS EXPANSION	10
		C050698	DAVISVILLE 84 - EMS EXPANSION	12
		C059663	CUTOUT MNTED RECLOSER PROGRAM_RI	120
		C059882	FLOOD CONTINGENCY PLAN NECO - D	1,020
		C065830	RECLOSER REPLACEMENT PROGRAM RI	600
		C074428	EMS EXPANSION - WAMPANOAG 48	125
		C074430	EMS EXPANSION - WOOD RIVER 85	125
		C074438	EMS EXPANSION - MERTON 51	129
		C074439	EMS EXPANSION - TIVERTON 2 33	150
		COS0015	OCEAN ST-DIST-RELIABILITY BLANKET.	1,125
		COS0025	OS-DIST-SUBSTATION LR/REL BLNKT	300
		C079195	3V0 Work in Rhode Island	200
		AMI - TBD	RI AMI/ VVO PILOT PROJECT	6,000
System Capacity & Performance Total				**45,764**
Grand Total				**108,767**

Attachment 3 Age Profiles

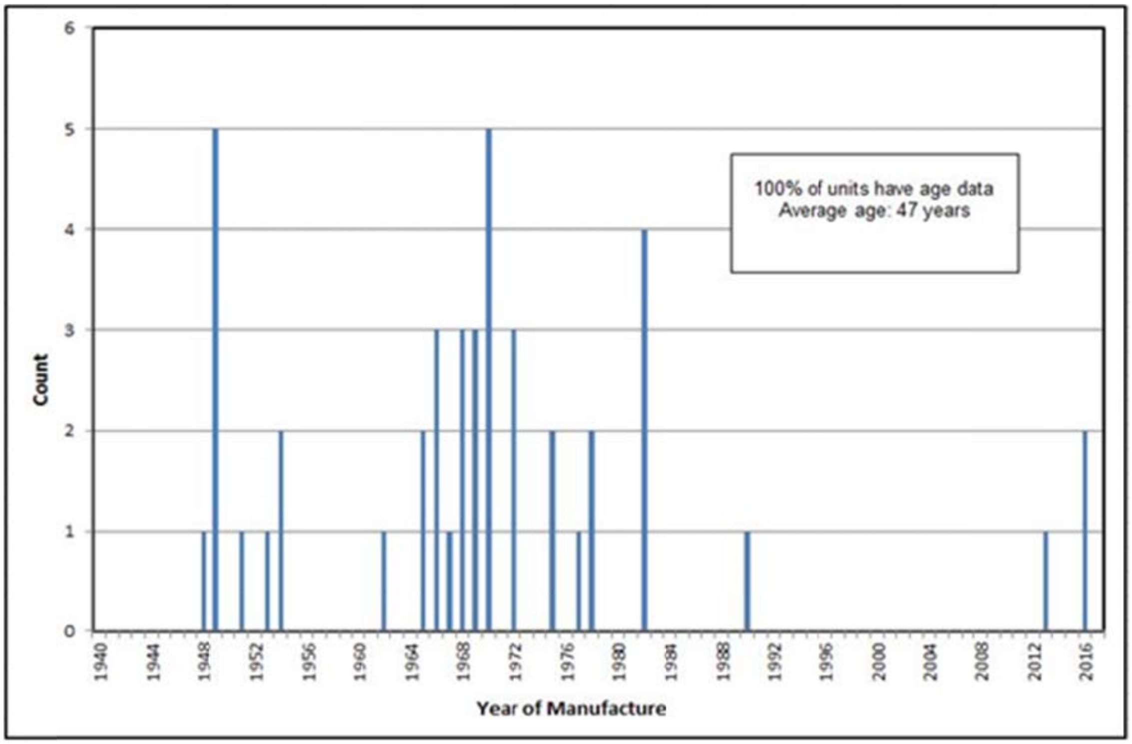
Rhode Island Distribution Pole Age Profile



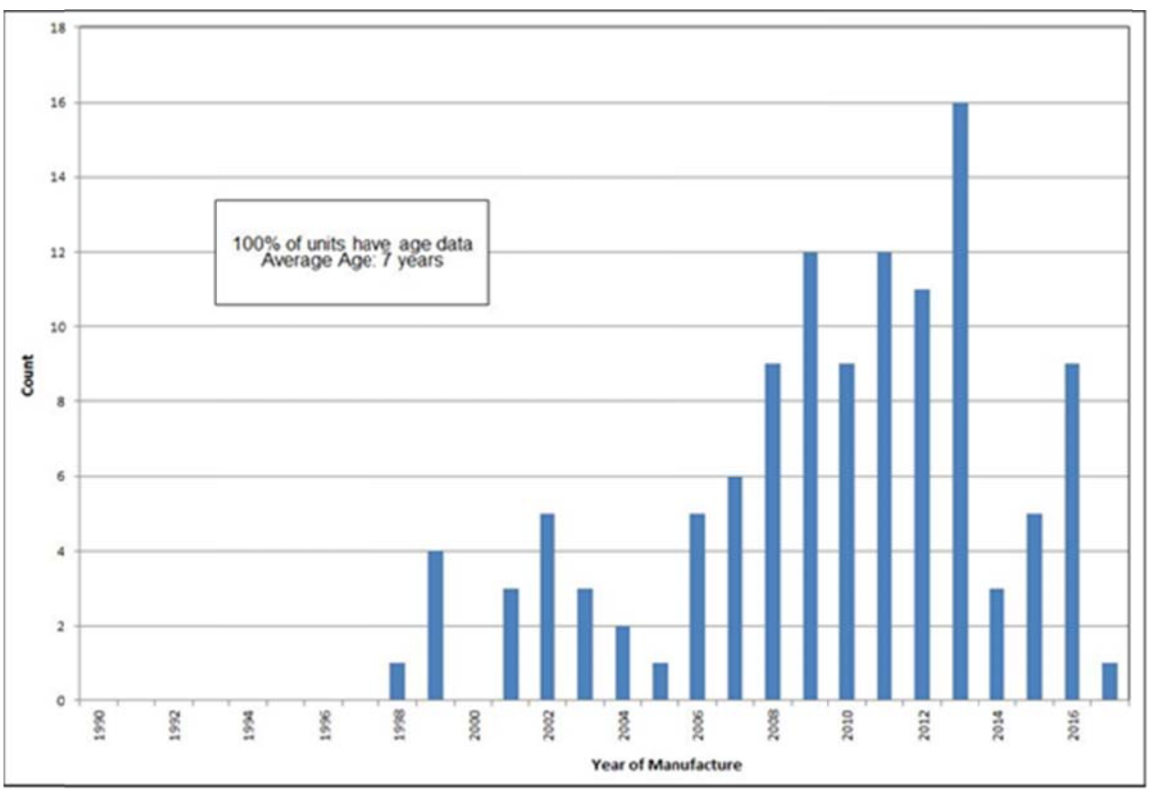
Rhode Island Distribution Transformer Age Profile



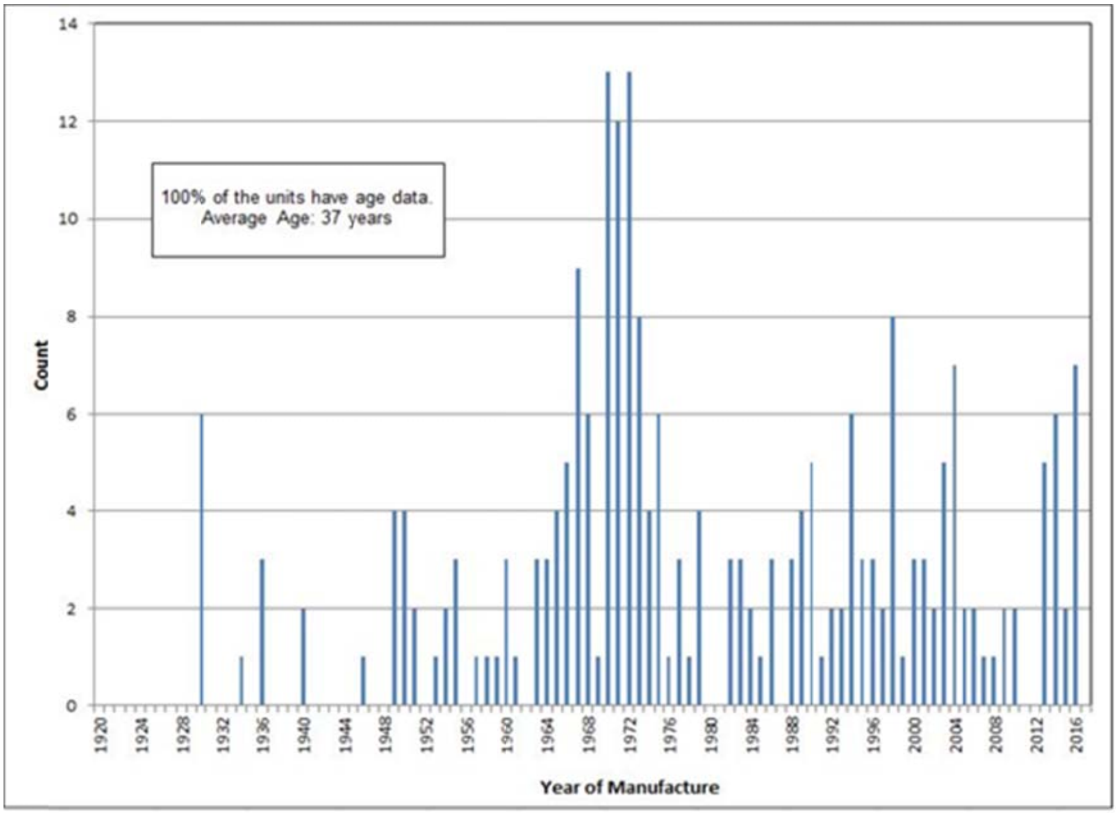
Rhode Island Metalclad Switchgear Age Profile



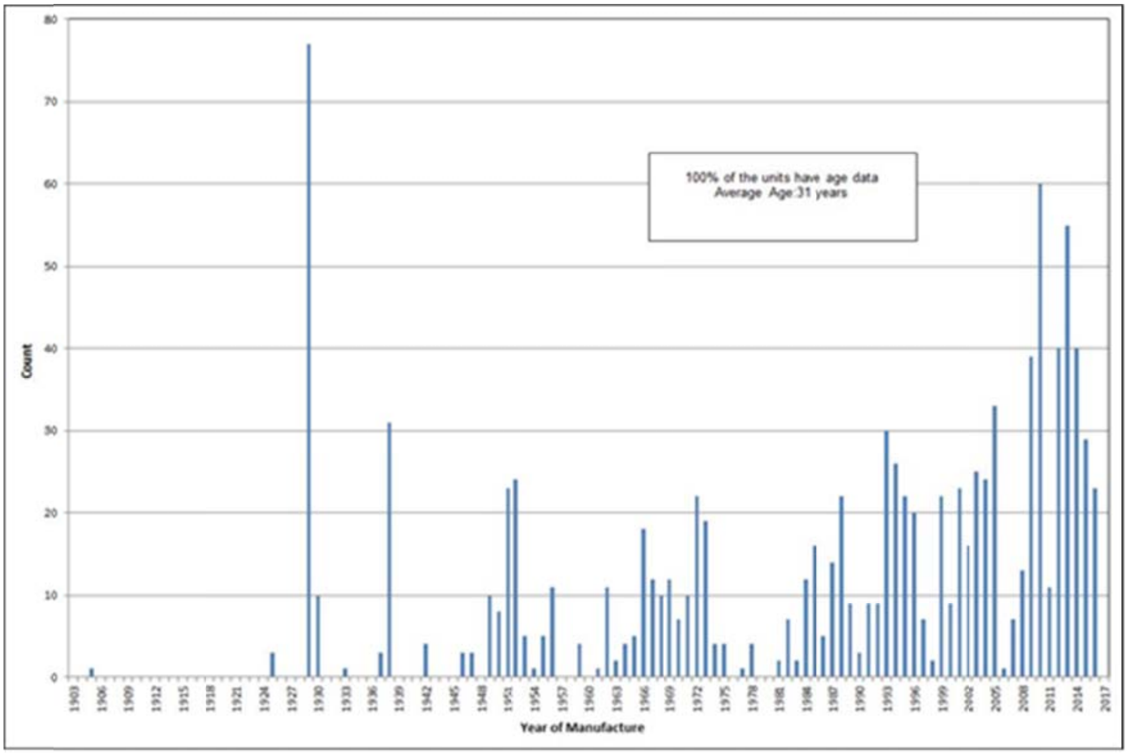
Rhode Island Substation Battery Age Profile



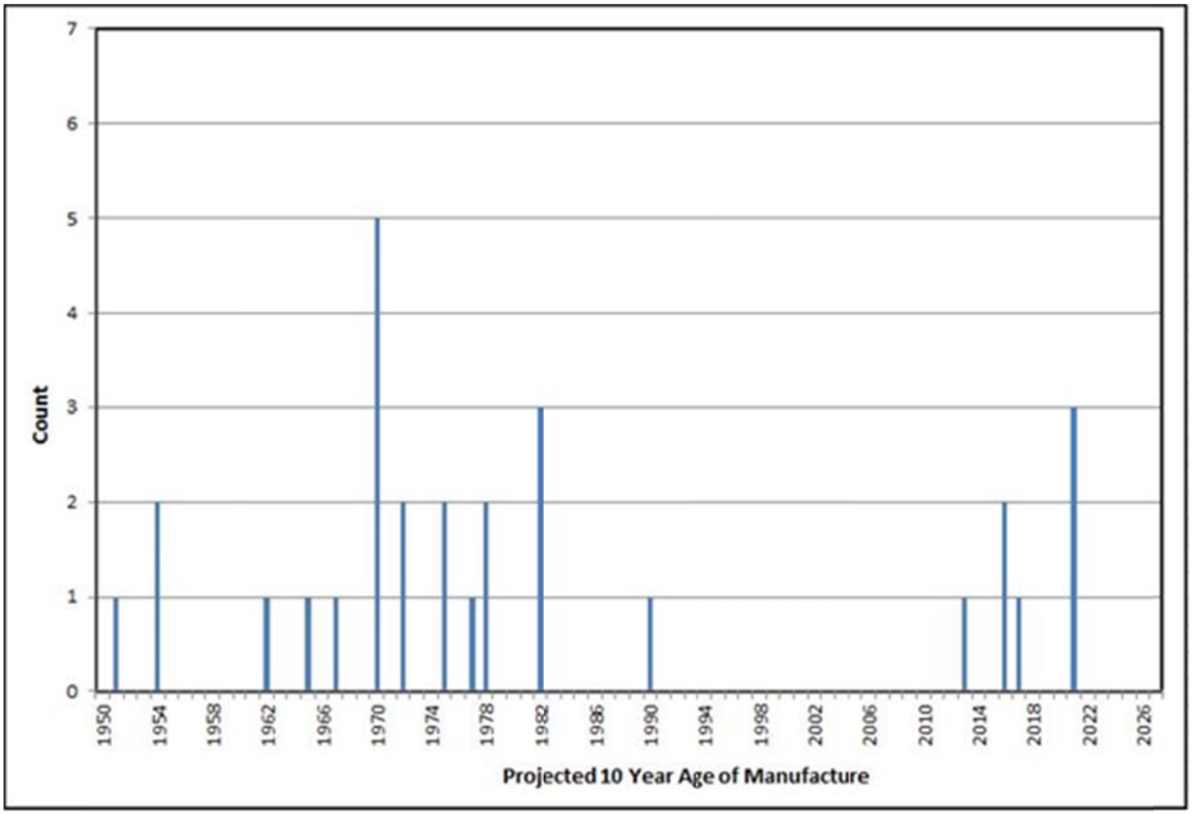
Rhode Island Substation Power Transformer Age Profile



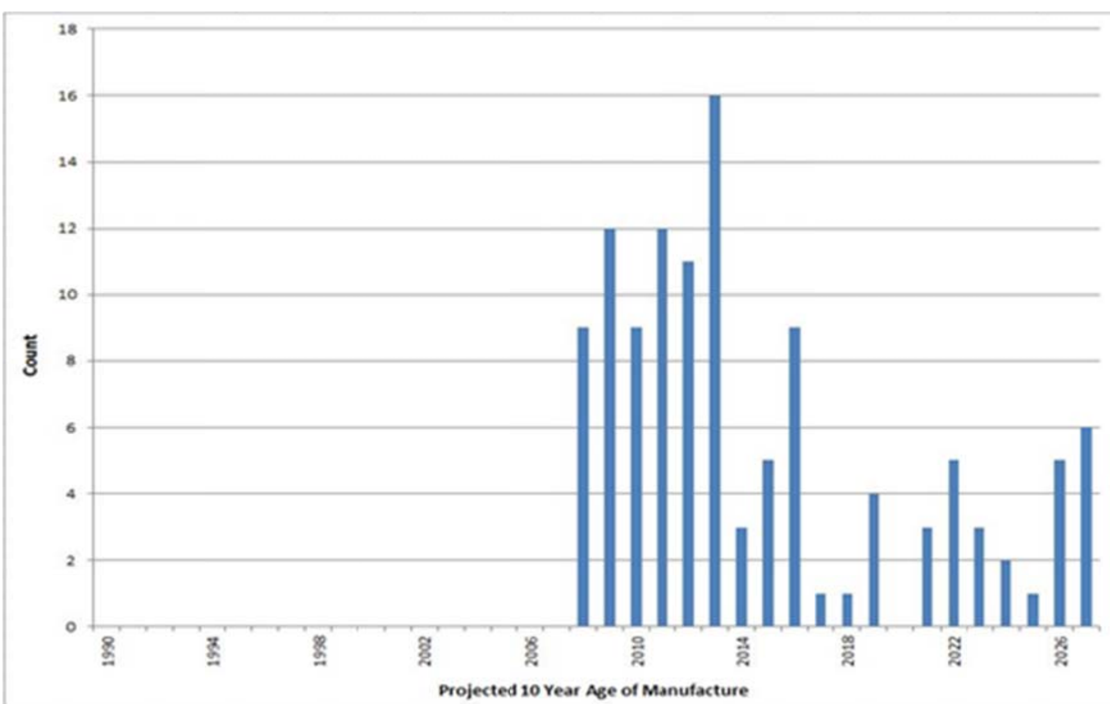
Rhode Island Circuit Breaker and Recloser Age Profile



Rhode Island Metalclad Switchgear Projected 10-Year Age Profile



Rhode Island Substation Battery Projected 10 Year Age Profile



Attachment 4

See also the Excel Version of this Attachment

Spending Rationale	Budget Class Codes	FY2018 ISR Budget	FY2019 Proposed Capital Budget	FY2020 Prelim Budget	FY2021 Prelim Capital Budget	FY2022 Prelim Capital Budget	FY2023 Prelim Capital Budget
Customer Request/Public Requirement	3rd Party Attachments	204	81	83	85	87	89
	Distributed Generation	1,106	(692)	(500)	(500)	(500)	(500)
	Land and Land Rights	223	225	230	235	240	246
	Meters - Dist	1,786	2,247	2,364	2,487	2,616	2,752
	New Business - Commercial	8,183	7,061	7,273	7,655	8,049	8,456
	New Business - Residential	5,616	5,247	5,517	5,831	6,150	6,485
	Outdoor Lighting - Capital	153	123	126	129	132	135
	Public Requirements	2,520	2,454	2,438	3,495	3,608	2,540
	Transformers & Related Equipment	2,060	2,259	2,373	2,493	2,619	2,752
Customer Request/Public Requirement Total		**21,853**	**19,005**	**19,904**	**21,910**	**23,001**	**22,955**
Damage/Failure	Damage/Failure	9,828	12,074	12,845	13,171	13,494	13,825
	Major Storms - Dist	1,550	1,600	1,650	1,700	1,750	1,800
Damage/Failure Total		**11,379**	**13,674**	**14,495**	**14,871**	**15,244**	**15,625**
Asset Condition - South St	Asset Replacement	25,773	3,720	1,800	-	-	-
Asset Condition - South St Total		**25,773**	**3,720**	**1,800**	**-**	**-**	**-**
System Capacity & Performance	Load Relief	21,079	35,849	26,390	18,585	17,590	9,061
	Reliability	3,422	9,916	6,079	8,055	10,097	13,285
System Capacity & Performance Total		**24,501**	**45,765**	**32,469**	**26,640**	**27,688**	**22,346**
Asset Condition	Asset Replacement	14,544	24,047	34,644	39,361	41,568	45,993
	Asset Replacement - I&M (NE)	1,600	1,700	4,625	5,150	5,425	6,200
	Safety	417	300	-	-	-	-
Asset Condition Total		**16,561**	**26,047**	**39,269**	**44,511**	**46,993**	**52,193**
Non-Infrastructure	Corporate/Admin/General	-	-	-	-	-	-
	General Equipment - Dist	378	306	312	318	324	331
	Telecommunications Capital - Dist	175	250	250	250	250	250
Non-Infrastructure Total		**553**	**556**	**562**	**568**	**574**	**581**
Grand Total		**100,620**	**108,767**	**108,500**	**108,500**	**113,500**	**113,700**

ISR Spending Rationale	ISR Category	Current Phase : Estimate +/- %	Total Current Estimate (Distribution)	Initial Estimate at time of First Sanction	Date of Last Sanction (partial or full)	Estimated Construction Start (earliest portion)	Estimated Construction End (last portion)	Pre-FY2018 Actual Capital Spend	FY2018 Actual Capital Spend (6-MTD)	Total-to-Date Actual Capital spend	Current Fcast FY2018 (6+6)	FINAL FY2018 Capital Budget	PRELIMINARY FY2019 Capital Budget	CHANGE FROM PREVIOUS DRAFT FY2019 Inc/(Dec)	December 2017 Negotiated Adjustments Inc/(Dec)	UPDATED FY2019 Capital Budget	UPDATED FY2020 Capital Budget	UPDATED FY2021 Capital Budget	UPDATED FY2022 Capital Budget	UPDATED FY2023 Capital Budget
System Capacity & Performance	Aquidneck Island (Newport projects)	In different phases ranging from engineering through construction : +/- 25%	55,827	53,585	Feb-2016	May-2018	Sep-2022	5,817	880	6,697	3,041	2,997	12,250	-	-	12,250	7,000	2,000	0	0
	Aquidneck Island (Jepson projects)					Apr-2018	Oct-2021	192	78	270	1,346	1,306	9,284	-	-	9,284	12,983	3,587	0	0
	Chase Hill (Hopkinton) & Related	Construction : +/- 10%	19,085	2,850	Dec-2015	Aug-2015	Jan-2019	12,865	1,788	14,653	2,883	3,856	3,900	-	-	3,900	0	0	0	0
	Quonset Sub	Construction : +/- 10%	7,432	4,520	Mar-2017	May-2016	Dec-2018	3,223	2,131	5,353	3,919	2,789	1,488	(200)	-	1,288	0	0	0	0
	New London Ave Substation #150	Construction : +/- 10%	15,391	2,900	May-2014	May-2017	Oct-2018	3,095	941	4,035	5,468	5,670	6,151	265	-	6,416	100	0	0	0
	East Providence Substation	Early Engineering, Permitting, Procurement : +50%/-25%	16,000	16,000	Feb-2017	Apr-2020	Oct-2022	-	134	134	134	-	800	(400)	-	400	2,679	4,019	5,900	0
	Warren Substation	Early Engineering, Permitting, Procurement : +50%/-25%	8,700	8,700	Feb-2017	Mar-2020	Oct-2022	-	76	76	76	80	450	-	-	450	1,441	2,159	3,532	0
	Kent County	Closeout : +/- 10%	3,610	3,800	Feb-2016	Apr-2014	Sep-2017	2,558	100	2,658	99	312	0	-	-	0	0	0	0	0
	Highland Drive	Closeout : +/- 10%	16,723	6,164	Jul-2014	Sep-2013	Oct-2017	2,340	921	3,262	1,427	1,329	0	-	-	0	0	0	0	0
	Kilvert St - DSub					Nov-2015	Aug-2017	3,738	32	3,770	57	-	0	-	-	0	0	0	0	0
	Kilvert St - DLine					Oct-2013	Oct-2017	3,435	2	3,437	49	-	0	-	-	0	0	0	0	0
Subtotal - System Capactiy & Performance Major Projects									7,082		18,499	18,338	34,323	(335)	-	33,988	24,203	11,765	9,432	0
	AMI Program								-		-	-	7,367	-	(1,367)	6,000	0	0	0	0
	Volt/Var								554		1,842	1,400	1,400	500	-	1,900	1,000	1,850	1,100	0
	Storm Hardening								-		-	-	0	-	-	0	1,096	0	0	0
	EMS								768		1,334	1,410	551	-	-	551	1,548	1,731	1,711	1,841
	OH Line Tranformer Replacement Program								148		386	475	550	-	-	550	600	650	700	725
	Other Flood								266		346	200	1,500	(480)	-	1,020	1,200	750	0	0
	Other Load Relief & Reliability								454		663	920	(777)	-	-	(777)	415	130	135	140
	Recloser Replacement								132		294	410	600	-	-	600	500	500	500	500
	3VO								-		-	-	200	-	-	200	200	200	200	200
	Blanket Projects - SCP								674		1,279	1,348	1,732	-	-	1,732	1,707	1,822	1,880	1,940
	Reserves - SCP								-		-	-	0	-	-	0	0	7,242	12,030	17,000
System Capacity & Performance Total									10,078		24,641	24,501	47,446	(315)	(1,367)	45,764	32,469	26,640	27,688	22,346
Asset Condition	South St Station Rebuild	Construction : +/- 25%	55,455	27,050	Jun-2015	Mar-2016	Jul-2018	21,431	6,533	27,964	23,381	25,773	3,500	220	-	3,720	1,800	0	0	0
	New Southeast Sub	Engineering : +50% / -25%	18,600	18,600	May-2015	May-2018	Aug-2020	74	47	122	375	435	2,700	-	-	2,700	6,100	4,400	350	0
	Flood - Westerly	Early Engineering, Permitting, Procurement : +50%/-25%	8,000	8,000	May-2015	Mar-2019	May-2021	16	-	16	-	-	635	(99)	-	536	3,051	2,589	853	0
	Flood - Warwick Mall Sub	Ready to Schedule : +/- 10%	850	(a)	(a)	Feb-2019	Aug-2019	354	23	378	23	-	580	-	-	580	0	0	0	0
	Flood - Hope Substation	Final engineering : +/- 25%	410	(a)	(a)	Jun-2018	Dec-2018	305	-	305	-	-	738	-	(738)	0	738	0	0	0
	Dyer Street - Indoor Sub	Engineering : +50% / -25%	14,154	14,154	Feb-2017	Dec-2018	Nov-2020	140	132	272	515	402	1,124	-	-	1,124	4,789	5,587	0	0
	Providence Study	Not Yet Sanctioned - FY2019 is Engineer Study costs transfer only							-		-	-	1,115	-	-	1,115	1,852	5,182	10,426	10,207
Subtotal - Asset Replacement Major Projects									6,736		24,294	26,610	10,392	121	(738)	9,775	18,330	17,758	11,630	10,207
	Asset Replacement - I&M (NE)								643		1,509	1,600	2,700	-	(1,000)	1,700	4,625	5,150	5,425	6,200
	Battery Replacement								50		134	199	300	-	-	300	150	150	150	150
	Metalclad Replacement								810		819	587	4,298	-	(2,000)	2,298	3,675	0	0	0
	Network Arc Flash								94		444	417	300	-	-	300	0	0	0	0
	RAPR								28		41	230	195	-	-	195	200	0	0	0
	Relay Replacements								69		174	431	0	-	-	0	0	0	0	0
	Substation Breakers & Reclosers								1,068		1,578	1,600	425	-	-	425	720	1,500	1,600	1,650
	Substation Transformers								246		850	1,535	3,550	-	-	3,550	73	0	0	0
	UG Cable								450		2,689	3,000	4,000	(100)	-	3,900	4,400	4,500	4,750	5,000
	URD								519		2,600	2,750	3,000	-	-	3,000	3,600	3,500	3,600	3,600
	UG Improvements								-		-	-	250	-	-	250	750	1,250	1,250	1,500
	Other Asset Replacement								1,619		2,941	926	1,551	46	(28)	1,569	1,983	185	0	0
	Blanket Projects - AC								2,176		4,477	2,450	2,506	-	-	2,506	2,563	2,621	2,681	2,743
	Reserves - AR								-		-	-	0	-	-	0	0	7,896	15,908	21,143
Asset Condition Total									14,506		42,552	42,334	33,467	67	(3,766)	29,768	41,069	44,511	46,993	52,193
Non-Infrastructure	General Equipment								116		247	378	306	-	-	306	312	318	324	331
	Telecommunications								76		164	175	250	-	-	250	250	250	250	250
	Corporate/Admin/General								(381)		(1,132)	-	0	-	-	0	0	0	0	0
Non-Infrastructure Total									(189)		(722)	553	556	-	-	556	562	568	574	581
Customer Requests/Public Requirements	Block Island								24		34	21	-	-	-	-	-	-	-	-
	3rd Party Attachments								114		235	204	81	-	-	81	83	85	87	89
	Land and Land Rights								143		255	223	225	-	-	225	230	235	240	246
	Meters - Dist								1,181		1,888	1,786	2,247	-	-	2,247	2,364	2,487	2,616	2,752
	New Business - Commercial								2,464		6,141	8,183	7,061	-	-	7,061	7,273	7,655	8,049	8,456
	New Business - Residential								2,193		5,172	5,616	5,247	-	-	5,247	5,517	5,831	6,150	6,485
	Outdoor Lighting - Capital								146		200	153	123	-	-	123	126	129	132	135
	Public Requirements								1,286		2,365	2,520	2,454	-	-	2,454	2,438	3,495	3,608	2,540
	Transformers & Related Equipment								1,017		2,060	2,060	2,259	-	-	2,259	2,373	2,493	2,619	2,752
	Distributed Generation								(2,700)		(2,137)	1,085	(940)	248	-	(692)	(500)	(500)	(500)	(500)
Customer Requests/Public Requirements Total									5,869		16,212	21,853	18,757	248	-	19,005	19,904	21,910	23,001	22,955
Damage/Failure	Damage/Failure								6,661		12,314	9,292	11,439	-	(250)	11,189	11,697	11,960	12,230	12,505
	Major Storms - Dist								492		1,372	1,550	1,600	-	-	1,600	1,650	1,700	1,750	1,800
	Reserves - DF								-		102	537	1,135	-	(250)	885	1,148	1,211	1,264	1,320
Damage/Failure Total									7,154		13,788	11,379	14,174	-	(500)	13,674	14,495	14,871	15,244	15,625
Grand Total									37,418		96,471	100,620	114,400	-	(5,633)	108,767	108,500	108,500	113,500	113,700

Section 3
Vegetation Mgmt.

Section 3

Vegetation Management Program
FY 2019 Electric ISR Plan Annual Filing

Section 3: Vegetation Management Program FY 2019 Proposal

The Company's Vegetation Management (VM) Program is an essential component of the Company's plan to maintain the safety and 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 have a significant impact on reliability. 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 causing an interruption in service.

As shown in Section 2, Chart 5, trees were responsible for approximately 85,147 customers interrupted in FY 2017, which represented 18.2 percent of the total interruptions. Trees were the leading cause of customer interruptions during FY 2017.

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 includes several different activities, each addressing a different aspect of utility vegetation management.

Cycle Pruning – The cycle pruning program is 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 includes 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 and consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a utility best 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. A review of the cycle pruning program from FY 2007 to FY 2017 shows, on average, a 20 percent improvement in customer interruptions (CI) per circuit in the first year after pruning.

The Company continues to recommend a four-year 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. The total overhead distribution mileage in Rhode Island is approximately 5,087 miles. To maintain a four-year pruning cycle, 1,272 miles need to be pruned each year. After detailed field analysis of the current circuits due at this time, the FY 2019 plan will require the pruning of 1,328 miles of distribution. The mileage is higher than usual due to the addition of 76 miles which were carried over from FY 2018. The pruning costs for FY 2018 were higher than anticipated and these circuits were carried over in order to stay within the FY 2018 budget of $9.8 million. It was determined that carrying these circuits over to

FY 2019 would not have a significant impact on costs or reliability. The estimated cost for distribution cycle pruning in FY 2019 is $6.15 million.

Enhanced Hazard Tree Mitigation (EHTM) – Hazard tree removal, as part of a complete utility vegetation management program, has also become a best industry practice. 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 indicates that fallen trees account for 46 percent of tree-related customer interruptions.

To address this issue, in 2008, the Company implemented the EHTM program 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. Therefore, hazard tree removal on three-phase sections of the distribution circuit intuitively provides the highest benefit per hazard tree removal dollar. EHTM uses an industry leading tree risk assessment protocol to identify hazard trees. To improve customer satisfaction and reliability, the Company has expanded its program to look beyond three phase sections on circuits experiencing multiple interruptions.

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,[9] a study of the Company's EHTM program was performed. From FY 2008 to FY 2017, the results show an average improvement of tree-related Customers Interruptions (CI) by circuit of 70 percent for the first year following project completion, which demonstrates a significant improvement in customer service reliability on targeted circuits.

Due to the spread of the Gypsy Moth throughout Rhode Island, the Company anticipates continued tree mortality during FY 2019. In order to be proactive with identifying and removing hazard trees, the Company is proposing to maintain the current VM budget of $1.25 million in FY 2019.

Sub-Transmission – This category includes VM 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, these circuits are not as easily balanced year-to-year. The total cost for the required FY 2019 sub-transmission VM work is $325,000. Currently, the Company has 22.47 miles of sideline work scheduled and will evaluate additional circuits in the coming months. There are also 94.87 acres of floor work scheduled this fiscal year.

9 Electric ISR Plan Vegetation Management Cost Benefit Report, filed September 5, 2012.

Chart 1
Sub-Transmission Vegetation Management Miles/Acres
(Includes both Distribution and Transmission Assets)

Sideline Pruning and Hazard Tree Removal (Miles)					
FY 2014	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**
59.52	34.09	82.16	99	43.31	22.47
Floor Treatment (Acres)					
FY 2014	**FY 2015**	**FY 2016**	**FY 2017**	**FY 2018**	**FY 2019**
222.05	214.97	89.28	119.66	220.14	94.87

Police Detail/Flagman – To safely perform the Cycle Pruning and EHTM, the Company is required to hire police details and flagman. For FY 2019, police detail costs are estimated to be $850,000. The Company considers several factors when estimating the police detail budget, including but not limited to, prior years costs per mile and percent of total budget, as well as the general police detail policies of the specific towns and municipalities where work is to be performed during the fiscal year. Police detail and flagging costs have remained relatively stable for the last few years. These costs remain well below similar police detail costs in Massachusetts, which also requires the use of police details. Specifically, in FY 2012, police detail costs in Massachusetts represented 14.6 percent of the total tree trimming budget for the state. Massachusetts police detail costs increased to 16.1 percent of the budget in FY 2013, and 17.5 percent of the budget in FY 2014. By contrast, in Rhode Island, police detail costs represented 5.6 percent of the tree trimming budget in FY 2012, 9.3 percent in FY 2013, 9.0 percent in FY 2014, 8.4 percent in FY 2015, 8.4 percent in FY 2016, and 8.2 percent in FY 2017. Police and flagging costs will be 8.6 percent for FY 2019.

Importantly, police detail and flagger costs are driven primarily by a number of factors outside of the Company's control, including a myriad of municipal requirements, work locations, and the hourly rates set by the municipalities. For example, the number and levels or required details vary by town and by traffic and road conditions. Also, certain towns mandate the use of police officers on a detail and limit or restrict the use of less expensive third-party flaggers. Depending on the town, different factors such as municipal ordinances, requirements in police union contracts or specific safety municipal requirements can play of role in the ability of the Company to manage its total police detail costs budget.

Notwithstanding these factors, the Company has adopted a number of changes to attempt to minimize police detail and flagger costs where possible. This includes removing police detail costs from the Company's Cycle Pruning program vendor bidding process and placing these costs into a separate police detail and flagger budget account. This permits the Company to separately track detail costs, and provides a more accurate historical basis for discussions with municipalities designed to mitigate police and detail costs, where possible. In addition, the VM program police protection processes are now also coordinated with the Company's electric and gas construction departments. The VM program police protection processes are also coordinated with the Company's community relations department so that the Company can discuss police detail requirements with communities and municipalities in advance of performing the work.

Additionally, since the Company's tree pruning work is performed by contractors, the Company has added police detail costs to the system used to evaluate overall contractor performance for a fiscal year, thus creating an incentive for contractors to actively focus on police details. To assist with this effort, the Company has also revised its contracting strategies by placing only one contractor in each municipality during a given year. This allows each contractor to develop a relationship with each town, and to better address communications with public safety officials.

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 with Cycle Pruning and 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 sporadic emergency calls to remove trees or 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 customer calls, weather, and system requirements. Each core activity separately consumes a small and variable proportion of the overall budget. Overall, for FY 2019, the Company expects to spend $1.2 million for the core activities.

Fiscal Year 2019 Vegetation Management Budget

As detailed in Chart 2 below, the FY 2019 Electric ISR Plan proposes to spend approximately $9.8 million for VM in FY 2019. This represents a 4 percent increase from the $9.4 million which was approved for FY 2018. The cause of this increased spend in FY 2019 is due to the 58 additional miles scheduled to be pruned in FY 2019 compared to FY 2018.

Chart 2
Vegetation Management Spending
($000)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
Cycle Prune (Base)	$5,110	$4,475	$5,414	$5,050	$5,500	$6,150
Hazard Tree – EHTM	$700	1,000	$1,000	$950	$1,250	$1,250
Sub-T (off & on road)	$639	$316	$220	$780	$650	$325
Police/Flagman Detail	$769	$650	$750	$714	$775	$850
Core Crew (All Other Activities) (incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.)	$1,312	$1,285	$1,500	$1,225	$1,225	$1,225
Total	**$8,530**	**$7,726**	**$8,884**	**$8,719**	**$9,400**	**$9,800**

Section 4
I&M Plan

Section 4

Inspection and Maintenance Plan and Other O&M
FY 2019 Electric ISR Plan Annual Filing

Section 4: Inspection and Maintenance Plan & Other O&M

Inspection and Maintenance Program

Consistent with the Company's condition-based asset management approach, the Company has implemented an Inspection and Maintenance (I&M) program to achieve a five-year inspection cycle of the overhead and underground assets. This program is intended to address deteriorated assets to ensure that 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. In addition to asset replacement, testing for elevated voltage should minimize potential safety issues related to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. Periodic inspection of equipment 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 also 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 during the inspections enhances the Company's Asset Management reviews and the development of projects and programs to maintain reliability performance and customer satisfaction. As shown in Section 2, Chart 5, Trees, Transmission, Intentional, and deteriorated equipment caused over 276,329 customer interruptions in FY 2017, accounting for approximately 58 percent of all customer interruptions in FY 2017. Although the I&M program is not a reliability-based program, the Company believes that the I&M program is an essential component to fulfilling its obligation to provide safe, reliable, and cost effective electric delivery service to customers in Rhode Island. The Company has agreed with the Division to assess the costs and benefits of the I&M program on an ongoing basis.

For FY 2019, the Plan signifies the continuation of the third year of the five-year inspection cycle for all distribution feeders. In addition, the Company will continue inspections of its manhole-based underground assets through working inspections in FY 2019.

The Company will continue elevated voltage testing within the Designated Contact Voltage Risk Areas (DCVRA's) designated in Docket No. 4237-A in FY 2019. However, as approved by the PUC in the FY 2018 Electric ISR Plan, the Company will test to 20% of the areas in FY 2019. This has resulted in a reduction in O&M costs in FY 2019 relative to prior years.

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

- The first five-year cycle for all distribution overhead I&M inspections was completed on schedule at the end of FY 2016. The proposed Plan is designed to continue year three of the second five-year inspection cycle and the continuation of repair work for items identified during the initial inspection cycle.

- Underground I&M inspections will continue to be performed as part of normal working inspections.

- Overhead Manual Contact Voltage testing will be performed as part of the cycle inspections.

- Underground Manual Contact Voltage testing will continue on a five-year cycle.

- Street Light Manual Contact Voltage testing will continue on a three-year cycle.

- Mobile Contact Voltage Testing in FY 2019 will test 20 percent of the DCVRA's.

FY 2019 Inspection and Maintenance Budget

As shown in Chart 1 below, the Company proposes a total I&M program budget of approximately $0.9 million for FY 2019. The associated capital costs, which are included in the capital budgets provided in Section 2 of this Electric ISR Plan, and the operating expense (Opex) related to capital investment (Capex) costs, which are Opex costs necessary to complete the capital construction, are $1.7 million and approximately $0.3 million, respectively. The Inspections and Repairs-related costs are $0.6 million, which include a component for completing 20 percent of the Contact Voltage Program as ordered in Docket No. 4237.

Chart 1
FY 2019 I&M Program Costs

	Total
Capital Costs (See Note 1)	**$ 1,700,000**
Opex Related to Capex	*$ 255,000*
Inspections and Repair Related Costs	*$ 612,000*
Total Operation and Maintenance Expenses	**$ 867,000**
Removal Costs	**$ 153,000**
Total Program Costs	**$ 2,720,000**

Note 1. Capital Costs are included in the $108.8 million capital budget provided in Section 2 of this Electric ISR Plan.

FY 2019 Other O&M Programs Budget

Chart 2 below includes the O&M costs associated with the following O&M projects for FY 2019:

- The Company's continuing the Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR) program and required FY 2019 operation and maintenance expenses for the existing pilot program feeders;
- The Company continuing the development of the Long Term Plan; and
- The O&M costs associated with the AMI Pilot Program which is described in greater detail in Section 2 under the System Capacity and Performance Category.

Chart 2
FY 2019 Other Programs O&M Costs

	Total
AMI PILOT Capital Costs	**$ 6,000,000**
AMI Project Related Opex Costs (One-time)	*$ 915,000*
Annual AMI-Related Opex Costs	*$ 185,000*
VVO/CVR	*$ 244,000*
Long Range Plan Study	*$ 25,000*
Total Operation and Maintenance Expenses	**$ 1,369,000**
Removal Costs	**$ 220,000**
Total Program Costs	**$ 7,589,000**

Note 1. Capital Costs are included in the $108.8 million capital budget provided in Section 2 of this Electric ISR Plan.

In summary, in FY 2019, the Company is planning to spend total O&M expenditures of $2.2 million, which include $0.9 million on I&M and $1.3 million on Other O&M Programs.

Section 5
Revenue Req.

Section 5

Revenue Requirement
FY 2019 Electric ISR Plan Annual Filing

Section 5: Revenue Requirement FY 2019 Proposal

Introduction

The attached proposed revenue requirement calculation reflects the revenue requirement related to the Company's proposed investment in its Electric ISR Plan for the fiscal year (FY) ended March 31, 2019.

As shown on Attachment 1 to Section 5 (Attachment 1), Page 1, Column (b), the Company's FY 2019 Electric ISR Plan cumulative revenue requirement is $32,754,385 and consists of the following elements: (1) operation and maintenance (O&M) expense associated with the Company's vegetation management (VM) activities, the Company's Inspection and Maintenance (I&M) program, and other programs, (2) the Company's capital investment in electric utility infrastructure, and (3) the FY 2019 Property Tax Recovery Adjustment. Lines 1, 2, and 3 of Column (b) reflect the forecasted FY 2019 revenue requirement related to current year O&M expenses for VM, I&M, and Other Programs of $9,800,000 and $867,000, and $1,369,000, respectively. As described in Section 4 of this document, the Electric ISR Plan 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. Gen. Laws §39- 2-25 and approved by the PUC in Docket No. 4237.[1] Contact Voltage Program costs are included in the $867,000 of I&M expenses referred to above. Line 4 includes a reduction of $163,749, which represents the portion of Contact Voltage Program costs that are being recovered in base rates from Docket No. 4323 and, therefore, should not be included in the Electric ISR revenue requirement.

[1] R.I. Gen. Laws § 39-2-25(6)(c).

The FY 2019 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $20,882,134 is shown on Line 20. This amount includes (1) the $3,087,133 revenue requirement on FY 2019 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 2, (2) the FY 2019 revenue requirements on incremental ISR capital investment for FY 2012 through FY 2018 totaling $14,699,828, and (3) the FY 2019 Property Tax Recovery Adjustment of $3,095,173from Attachment 1, Page 21. Importantly, the incremental capital investment for the FY 2019 Electric ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4323 for FY 2012, FY 2013 and FY 2014. 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. The total annual FY 2019 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $32,754,385, as reflected in Column (b) on Line 21, and is equal to the sum of Lines 5 and 20.

For illustration purposes only, Column (c) of Page 1 provides the FY 2019 revenue requirement for the respective vintage year capital investments. 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.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2019 Electric ISR Plan revenue requirement includes $9,800,000 of VM, $867,000 of I&M expenses, and $1,369,000 of Other Program expenses as shown on Page 1, Lines 1, 2, and 3 in Column (b) of Attachment 1. As described above, the Electric ISR Plan I&M component includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Program. However, the Company's base rates are recovering $163,749 of voltage monitoring costs, so that amount is being deducted on Line 4 in determining total FY 2019 O&M expenses of $11,872,251, as shown on Line 5 of Attachment 1.

Electric Infrastructure Investment

Incremental Capital Investment

Page 2 of Attachment 1 calculates the revenue requirement of incremental capital investment associated with the Company's FY 2019 Electric ISR Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. The proposed capital investment and estimated cost of removal were obtained from Chart 10 of Section 2 in this Plan. The FY 2019 revenue requirement also includes the incremental capital investment associated with the Company's FY 2012 through FY 2018 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4323 for FY 2012 through FY 2014. Page 18 of Attachment 1 calculates the incremental FY 2012 through FY 2014 ISR capital investment and the related incremental cost of removal and incremental retirements for the FY 2019 electric ISR revenue requirement. The calculations on Page 18 compare ISR-eligible capital investment, cost of removal and retirements for FY 2012 through FY 2014 to the corresponding amounts reflected in Docket No. 4323.

For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations, and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. This ISR plan limits the amount of eligible discretionary capital investments made since April 1, 2011 to the lesser of cumulative discretionary capital additions, or the cumulative amount of discretionary project spend as agreed to by the Division and as approved by the PUC since the April 1, 2011 effective date of this ISR mechanism. This limitation on discretionary capital investment will be analyzed as a part of the previously mentioned annual reconciliation of the proposed ISR investment to actual investment activity after the conclusion of the fiscal year.

Electric Infrastructure Revenue Requirement

The revenue requirement calculation on incremental electric infrastructure investment for vintage year FY 2019 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. 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 because 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 three-year average percentage of retirements to additions during FY 2015 through FY 2017, and have been deducted from the total depreciable capital amount as shown on Lines 4 through 6. Incremental book depreciation expense on Line 16 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,[2] 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 17 and 23, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 18 through 23, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate, net of any tax NOL and proration adjustment. The calculation of tax depreciation is described below. The average rate base is shown on Line 28. This amount is multiplied by the pre-tax rate of return approved by the PUC in Docket No. 4323, as shown on Line 29, to compute the return and tax portion of the incremental revenue

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

requirement, as shown on Line 30. As reflected on Line 31, incremental depreciation expense is added to this amount. The sum of these amounts reflects the annual revenue requirement associated with the capital investment portion of the Company's Electric ISR Plan on Line 32, which is carried forward to Page 1, Line 13, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018 through FY 2012 incremental ISR Plan capital investments are shown on Attachment 1 at Pages 4, 6, 8, 10, 12, 14 and 16. These capital investment revenue requirement and property tax amounts are added to the total O&M expenses on Attachment 1, Page 1, Line 5, to derive the total FY 2019 Electric ISR Plan revenue requirement of $32,754,385, as shown on Page 1, Line 19. This represents a $5,917,206increase from the FY 2018 Electric ISR Plan revenue requirement, as shown on Line 22.

Tax Depreciation Calculation

The tax depreciation calculation for FY 2019 is provided on Attachment 1, Page 3. The tax depreciation amount assumes that a portion of the capital investment, as shown on Line 1 of Page 3, 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.[3] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Page 3, Lines 4 through 12 for FY 2019. In 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 31, 2012. The 50 percent bonus depreciation rate was later extended through December 31, 2013 and then extended further through December 31, 2017 through the Protecting Americans from Tax Hikes (PATH) Act. The PATH Act also extended bonus depreciation through 2019 with the rate phasing down to 40 percent in 2018 and 30 percent in 2019. In accordance with the PATH Act, capital investments made from April 2018 through December 2018 are eligible for 40 percent bonus depreciation, and capital investments made from January 2019 through March 2019 are eligible for 30 percent bonus depreciation as shown on Page 3, Lines 9 and 10.

---

[3] In 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 which is 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, which National Grid Holdings, Inc. filed on December 11, 2009. 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.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System (MACRS) tax depreciation rate. Also, the IRS clarified its tangible property regulations, and, consequently, the Company submitted a §481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. This election was submitted to the PUC, as required under IRS rules, on December 17, 2015. The late partial disposition election was made to protect the Company's deduction of cost of removal (COR). Otherwise, the Company would have been required to make a §481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100% deductible. The vintage FY 2015 through FY 2019 tax depreciation calculations in this filing now include an additional tax deduction related to this change in accounting issue. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, MACRS depreciation, the tax loss on retirements, and cost of removal. These annual total tax depreciation amounts are carried forward to Page 2 of Attachment 1, and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for FY 2018 through FY 2012 on Attachment 1, Pages 5, 7, 9, 11, 13, 15 and 17.

Federal Net Operating Loss

Tax net operating losses (NOLs) are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. This does not mean that the Company is suffering losses in its financial statements; instead, the Company's tax NOLs are the result of the significant tax deductions that have been generated in recent years by the bonus depreciation and capital repairs tax deductions. In addition to first-year bonus tax depreciation, the US tax code allows the Company to classify certain costs as repairs expense, which the Company takes as an immediate deduction on its income tax return; however, these costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions have exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2016, with the exception of FY 2011. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future. If the company is able to utilize any of its currently accumulated NOLs in future tax years, the benefit will flow to customers in the particular fiscal year the benefit is reflected in the Company's federal income tax return.

NOLs are an offset to the Company's accumulated deferred income taxes. Accumulated deferred income taxes, which equals the difference between book depreciation and tax depreciation on ISR capital investment times the effective rate, are included as a credit or reduction in the calculation of rate base. However, since the Company was not able to fully utilize all of its tax deductions, tax NOLs were recorded which offset a portion of the rate base reduction for accumulated deferred income taxes.

As indicated above, the Company has generated NOLs on its fiscal year tax returns from FY 2009 to FY 2016, with the exception of FY 2011. The Company is currently estimating that in FY 2017, FY 2018 and FY 2019 there will be taxable income; therefore, the NOL amount is zero. Actual and estimated NOLs can be found in the FY 2016, FY 2015, FY 2014, FY 2013, and FY 2012 revenue requirement calculations on Pages 8, 10, 12, 14 and 16, respectively. If the Company is able to utilize any of its currently accumulated NOLs in future tax years that benefit will be flowed through to customers.

<u>Accumulated Deferred Income Tax Proration Adjustment</u>

The Electric ISR Plan includes a proration calculation regarding the accumulated deferred income tax (ADIT) balance included in rate base. The calculation fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). This regulation stipulates normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly. The penalty of a normalization violation is the loss of all federal income tax deductions for accelerated depreciation, including bonus depreciation. Any regulatory filing that includes capital expenditures, book depreciation expense and ADIT related to those capital expenditures must follow the normalization requirements. When the regulatory filing is based on a future period, the deferred tax must be prorated to reflect the period of time that the ADIT balances are in rate base. This filing includes FY 2018, FY 2019 and FY 2020 proration calculations at Page 25, 26, and 27, respectively, the effects of which are included in each year's respective revenue requirement.

<u>Property Tax Recovery Adjustment</u>

The Property Tax Recovery Adjustment is shown on Pages 20 through 22 of Attachment 1. The method used to recover property tax expense under the ISR was modified by the rate case settlement agreement in Docket No. 4323. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company includes 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 adjustment also includes 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. This provision of the settlement agreement became effective for ISR property tax recovery periods subsequent to the January 31, 2014 end of the rate year. The FY 2019 revenue requirement includes $3,095,173 for the net property tax recovery adjustment.

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 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$9,400,000	$9,800,000	
2	Current Year Inspection & Maintenance (I&M)	$1,069,800	$867,000	
3	Current Year Other Programs		$1,369,000	
4	Electric Contact Voltage expenses included in RIPUC Docket No. 4323	($163,749)	($163,749)	
5	**Total O&M Expense Component of Revenue Requirement**	**$10,306,051**	**$11,872,251**	
	Capital Investment:			
6	Actual Revenue Requirement on Incremental FY 2012 Capital included in ISR Rase Base	$268,500	$270,562	$270,928
7	Actual Revenue Requirement on Incremental FY 2013 Capital included in ISR Rate Base	($1,074,896)	($999,876)	($948,845)
8	Actual Revenue Requirement on Incremental FY 2014 Capital included in ISR Rate Base	$706,927	$659,372	$615,340
9	Actual Revenue Requirement on FY 2015 Capital included in ISR Rate Base	$3,758,934	$3,566,424	$3,379,479
10	Actual Revenue Requirement on FY 2016 Capital included in ISR Rate Base	$3,967,711	$3,635,950	$3,487,064
11	Actual Revenue Requirement on FY 2017 Capital included in ISR Rate Base	$4,415,399	$3,395,335	$3,216,540
12	Actual Revenue Requirement on FY 2018 Capital included in ISR Rate Base	$2,267,653	$4,172,061	$3,710,489
13	Actual Revenue Requirement on FY 2019 Capital included in ISR Rate Base	$0	$3,087,133	$5,805,602
14	Subtotal	$14,310,230	$17,786,961	$19,536,598
15	FY 2018 Property Tax Recovery Adjustment	$3,906,950		
16	FY 2019 Property Tax Recovery Adjustment		$3,095,173	
17	True-Up for FY 2012 through FY 2016 Transmission - Related Net Operating Losses ("NOL")	($1,125,115)	$0	
18	True-Up for FY 2013 through FY 2016 Work Order Write Off Adjustment: Capital Investment	($560,347)	$0	
19	True-Up for FY 2013 through FY 2016 Work Order Write Off Adjustment: Property Tax	($589)	$0	
20	**Total Capital Investment Component of Revenue Requirement**	**$16,531,128**	**$20,882,134**	
21	**Total Fiscal Year Revenue Requirement**	**$26,837,179**	**$32,754,385**	
22	**Total Updated Fiscal Year Rate Adjustment**		**$5,917,206**	

Column (a) - as Approved per RIPUC Docket No. 4682
Column (b)
1 Vegetation Management per Section 3, Chart 2
2 Inspection & Maintenance per Section 4, Chart 1
3 Other Program Expense per Section 4, Chart 2
5 Sum of Lines 1 through 4
6 Page 16 of 27, Line 30
7 Page 14 of 27, Line 32
8 Page 12 of 27, Line 32
9 Page 10 of 27, Line 32
10 Page 8 of 27, Line 32
11 Page 6 of 27, Line 31
12 Page 4 of 27, Line 32
13 Page 2 of 27, Line 32
14 Sum of Lines 6 through 13
16 Page 21 of 27, Line 128
20 Sum of Lines 14 through 19
21 Line 5 + Line 20
22 Current Year Line 21 - Prior Year Line 21

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2019 Actual Incremental Capital Investment

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*	Section 2, Chart 10		$30,991,000	$0
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Section 2, Chart 10		$60,346,000	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$91,337,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$91,337,000	$0
5	Retirements	Line 4 * 29.85%	1/	$27,264,095	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$64,072,906	$64,072,906
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$91,337,000	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$48,305,226	$48,305,226
10	Cost of Removal	Section 2, Chart 10		$12,054,000	$12,054,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$60,359,226**	**$60,359,226**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%
13	Vintage Year Tax Depreciation:				
14	2019 Spend	Page 3 of 27, Line 21		$67,683,160	$2,940,157
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$67,683,160	$70,623,317
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50% ; Column (b) = Line 6 * Line 12		$1,089,239	$2,178,479
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,089,239	$3,267,718
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$66,593,921	$67,355,599
19	Effective Tax Rate			35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$23,307,872	$23,574,460
21	Less: FY 2019 Federal NOL	Page 23 of 27, Line13(p)		$0	$0
22	Less: Proration Adjustment	Col (a) = Page 26 of 27, Line 40; Col (b) = Page 27 of 27, Line 40		($5,316,672)	($144,736)
23	Net Deferred Tax Reserve	Sum of Lines 20 through 22		$17,991,201	$23,429,723
	Rate Base Calculation:				
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$60,359,226	$60,359,226
25	Accumulated Depreciation	-Line 17		($1,089,239)	($3,267,718)
26	Deferred Tax Reserve	-Line 23		($17,991,201)	($23,429,723)
27	Year End Rate Base	Sum of Lines 24 through 26		$41,278,786	$33,661,784
	Revenue Requirement Calculation:				
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$20,639,393	$37,470,285
29	Pre-Tax ROR		2/	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,997,893	$3,627,124
31	Book Depreciation	Line 16		$1,089,239	$2,178,479
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$3,087,133**	**$5,805,602**

1/ Based on three year average FY 2017, FY 2016, and FY 2015 actual retirements as a percent of capital investment

2/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2019 Incremental Capital Investments

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)
	Capital Repairs Deduction				
1	Plant Additions	Page 2 of 27, Line 3		$91,337,000	
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.08%	
3	Capital Repairs Deduction	Line 1 * Line 2		$26,560,800	
	Bonus Depreciation				
4	Plant Additions	Line 1		$91,337,000	
5	Less Capital Repairs Deduction	Line 3		$26,560,800	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$64,776,200	
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$64,128,438	
9	Bonus Depreciation Rate (April 2018 - December 2018)	1 * 75% * 40%		30.00%	
10	Bonus Depreciation Rate (January 2019 - March 2019)	1 * 25% * 30%		7.50%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10		37.50%	
12	Bonus Depreciation	Line 8 * Line 11		$24,048,164	
	Remaining Tax Depreciation				
13	Plant Additions	Line 1		$91,337,000	
14	Less Capital Repairs Deduction	Line 3		$26,560,800	
15	Less Bonus Depreciation	Line 12		$24,048,164	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$40,728,036	$40,728,036
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,527,301	$2,940,157
19	FY19 Loss incurred due to retirements	Per Tax Department	2/	$3,492,895	
20	Cost of Removal	Page 2 of 27, Line 10		$12,054,000	
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$67,683,160	$2,940,157

1/ Capital Repairs percentage is based on a three year average 2014, 2015, and 2016 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions.

2/ FY 2019 estimated tax loss on retirements is based on FY 2017 actuals (Page 7 of 27, Line 19).

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*	Section 2, Page 27 of 27, Chart 11		$32,731,000	$0	$0
	Discretionary Capital					
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Section 2, Page 27 of 27, Chart 11		$42,112,000	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$74,843,000	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$74,843,000	$0	$0
5	Retirements	Line 4 * 21.99%	1/	$16,457,400	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$58,385,600	$58,385,600	$58,385,600
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$74,843,000	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$31,811,226	$31,811,226	$31,811,226
10	Cost of Removal	Section 2, Page 27 of 27, Chart 11		$9,646,000	$9,646,000	$9,646,000
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$41,457,226**	**$41,457,226**	**$41,457,226**
	Deferred Tax Calculation:					
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%	3.40%
13	Vintage Year Tax Depreciation:					
14	2018 Spend	Page 3 of 26, Line 21		$57,010,767	$2,193,014	$2,028,363
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$57,010,767	$59,203,781	$61,232,144
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50% ; Column (b) = Line 6 * Line 12		$992,555	$1,985,110	$1,985,110
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$992,555	$2,977,666	$4,962,776
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$56,018,212	$56,226,115	$56,269,368
19	Effective Tax Rate			35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$19,606,374	$19,679,140	$19,694,279
21	Less: FY 2018 Federal NOL	Page 21 of 26, Line12(n)		$0	$0	$0
22	Less: Proration Adjustment	Col (b) = Page 26 of 27, Line 40; Col (c) = Page 27 of 27, Line 40		($5,486,704)	($39,506)	($8,219)
23	Net Deferred Tax Reserve	Sum of Lines 20 through 22		$14,119,670	$19,639,634	$19,686,060
	Rate Base Calculation:					
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$41,457,226	$41,457,226	$41,457,226
25	Accumulated Depreciation	-Line 17		($992,555)	($2,977,666)	($4,962,776)
26	Deferred Tax Reserve	-Line 23		($14,119,670)	($19,639,634)	($19,686,060)
27	Year End Rate Base	Sum of Lines 24 through 26		$26,345,000	$18,839,926	$16,808,390
	Revenue Requirement Calculation:					
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$13,172,500	$22,592,463	$17,824,158
29	Pre-Tax ROR		2/	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,275,098	$2,186,950	$1,725,379
31	Book Depreciation	Line 16		$992,555	$1,985,110	$1,985,110
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$2,267,653**	**$4,172,061**	**$3,710,489**

1/ Based on three year average FY 2016, FY 2015, and FY 2014 actual retirements as a percent of capital investment

2/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2018 Incremental Capital Investments

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)
	Capital Repairs Deduction					
1	Plant Additions	Page 2 of 26, Line 3		$74,843,000		
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.38%		
3	Capital Repairs Deduction	Line 1 * Line 2		$17,498,293		
	Bonus Depreciation					
4	Plant Additions	Line 1		$74,843,000		
5	Less Capital Repairs Deduction	Line 3		$17,498,293		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$57,344,707		
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$56,771,260		
9	Bonus Depreciation Rate (April 2017 - December 2017)	1 * 75% * 50%		37.50%		
10	Bonus Depreciation Rate (January 2018 - March 2018)	1 * 25% * 40%		10.00%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10		47.50%		
12	Bonus Depreciation	Line 8 * Line 11		$26,966,349		
	Remaining Tax Depreciation					
13	Plant Additions	Line 1		$74,843,000		
14	Less Capital Repairs Deduction	Line 3		$17,498,293		
15	Less Bonus Depreciation	Line 12		$26,966,349		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$30,378,358	$30,378,358	$30,378,358
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,139,188	$2,193,014	$2,028,363
19	FY18 Loss incurred due to retirements	Per Tax Department	2/	$1,760,937		
20	Cost of Removal	Page 2 of 26, Line 10		$9,646,000		
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$57,010,767	$2,193,014	$2,028,363

1/ Capital Repairs percentage is based on a three year average 2013, 2014, and 2015 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions.

2/ FY 2018 estimated tax loss on retirements is based on FY 2016 actuals (Page 7 of 26, Line 19).

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2017 Actual Incremental Capital Investment

Line No.				Fiscal Year 2017 (a)	Fiscal Year 2018 (b)	Fiscal Year 2019 (c)	Fiscal Year 2020 (d)
	Capital Additions Allowance						
	Non-Discretionary Capital						
1	Non-Discretionary Additions	Attachment PSA-1, Page 3, Table 1		$28,593,675	$0	$0	$0
	Discretionary Capital						
2	Lesser of Actual Cumulative Discretionary Capital Additions or Spending, or Approved Spending	Page 19 of 27, Line 12		$46,895,663	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$75,489,338	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$75,489,338	$0	$0	$0
5	Retirements		1/	$22,244,993	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$53,244,346	$53,244,346	$53,244,346	$53,244,346
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$75,489,338	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$32,457,565	$32,457,565	$32,457,565	$32,457,565
10	Total Cost of Removal	Attachment PSA-1, Page 4, Table 2		$7,806,949	$7,806,949	$7,806,949	$7,806,949
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$40,264,513**	**$40,264,513**	**$40,264,513**	**$40,264,513**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%	3.40%	3.40%
	Vintage Year Tax Depreciation:						
13	2017 Spend	Page 7 of 27, Line 21		$58,425,852	$2,127,323	$1,967,605	$1,820,263
14	Cumulative Tax Depreciation	Prior Year Line 14 + Current Year Line 13		$58,425,852	$60,553,175	$62,520,779	$64,341,042
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$905,154	$1,810,308	$1,810,308	$1,810,308
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		$905,154	$2,715,462	$4,525,770	$6,336,077
17	Cumulative Book / Tax Timer	Line 14 - Line 16		$57,520,698	$57,837,713	$57,995,010	$58,004,965
18	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18		$20,132,244	$20,243,200	$20,298,253	$20,301,738
20	Less: FY 2017 Federal NOL	Page 23 of 27, Line13(n)		$0	$0	$0	$0
21	Less: Proration Adjustment	Col (c) = Page 26 of 27, Line 40; Col (d) = Page 27 of 27, Line 40		$0	($16,852)	$14,700	($1,892)
22	Net Deferred Tax Reserve	Line 19 + Line 20		$20,132,244	$20,226,348	$20,312,953	$20,299,846
	Rate Base Calculation:						
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$40,264,513	$40,264,513	$40,264,513	$40,264,513
24	Accumulated Depreciation	-Line 16		($905,154)	($2,715,462)	($4,525,770)	($6,336,077)
25	Deferred Tax Reserve	-Line 22		($20,132,244)	($20,226,348)	($20,312,953)	($20,299,846)
26	Year End Rate Base	Sum of Lines 23 through 25		$19,227,115	$17,322,704	$15,425,791	$13,628,590
	Revenue Requirement Calculation:						
27	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$9,613,558	$18,274,910	$16,374,247	$14,527,190
28	Pre-Tax ROR		2/	9.68%	9.68%	9.68%	9.68%
29	Return and Taxes	Line 27 * Line 28		$930,592	$1,769,011	$1,585,027	$1,406,232
30	Book Depreciation	Line 15		$905,154	$1,810,308	$1,810,308	$1,810,308
31	**Annual Revenue Requirement**	**Line 29 + Line 30**		**$1,835,746**	**$3,579,319**	**$3,395,335**	**$3,216,540**

1/ Actual Retirements
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%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2017 Incremental Capital Investments

Line No.				Fiscal Year 2017 (a)	Fiscal Year 2018 (b)	Fiscal Year 2019 (c)	Fiscal Year 2020 (d)
	Capital Repairs Deduction						
1	Plant Additions	Page 6 of 27, Line 3		$75,489,338			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	22.70%			
3	Capital Repairs Deduction	Line 1 * Line 2		$17,136,080			
	Bonus Depreciation						
4	Plant Additions	Line 1		$75,489,338			
5	Less Capital Repairs Deduction	Line 3		$17,136,080			
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$58,353,258			
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%			
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$57,769,726			
9	Bonus Depreciation Rate (April 2016 - December 2016)	1 * 75% * 50%		37.50%			
10	Bonus Depreciation Rate (January 2017 - March 2017)	1 * 25% * 50%		12.50%			
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%			
12	Bonus Depreciation	Line 8 * Line 11		$28,884,863			
	Remaining Tax Depreciation						
13	Plant Additions	Line 1		$75,489,338			
14	Less Capital Repairs Deductions	Line 3		$17,136,080			
15	Less Bonus Depreciation	Line 12		$28,884,863			
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$29,468,395	$29,468,395	$29,468,395	$29,468,395
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,105,065	$2,127,323	$1,967,605	$1,820,263
19	FY17 Loss incurred due to retirements	Per Tax Department		$3,492,895			
20	Cost of Removal	Page 6 of 27, Line 10		$7,806,949			
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$58,425,852	$2,127,323	$1,967,605	$1,820,263

1/ Capital Repairs percentage is based on a three year average, 2012, 2013 and 2014 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
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2016 Actual Incremental Capital Investment

Line No.				Fiscal Year 2016 (a)	Fiscal Year 2017 (b)	Fiscal Year 2018 (c)	Fiscal Year 2019 (d)	Fiscal Year 2020 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*	Per RIPUC Docket No. 4539		$35,964,438	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books		$672,272	$0	$0	$0	$0
	Discretionary Capital							
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4539		$35,488,464	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books		($121,728)	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 1a + Line 2 + Line 2a		$72,003,445	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$72,003,445	$0	$0	$0	$0
5	Retirements		1/	$28,489,814	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$43,513,631	$43,513,631	$43,513,631	$43,513,631	$43,513,631
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$72,003,445	$0	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$28,971,671	$28,971,671	$28,971,671	$28,971,671	$28,971,671
10	Cost of Removal	Per RIPUC Docket No. 4539	2/	$8,192,983	$8,192,983	$8,192,983	$8,192,983	$8,192,983
10a	Work Order Write Off Adjustment	Per Company's books		($19,884)	($19,884)	($19,884)	($19,884)	($19,884)
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**		**$37,144,770**	**$37,144,770**	**$37,144,770**	**$37,144,770**	**$37,144,770**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%	3.40%	3.40%	3.40%
13	Vintage Year Tax Depreciation:							
14	2016 Spend	Page 9 of 27, Line 21		$60,569,127	$1,868,699	$1,728,398	$1,598,969	$1,478,858
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$60,569,127	$62,437,826	$64,166,224	$65,765,193	$67,244,051
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$739,732	$1,479,463	$1,479,463	$1,479,463	$1,479,463
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$739,732	$2,219,195	$3,698,659	$5,178,122	$6,657,586
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$59,829,395	$60,218,631	$60,467,565	$60,587,071	$60,586,465
19	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$20,940,288	$21,076,521	$21,163,648	$21,205,475	$21,205,263
21	Less: FY 2016 Federal NOL	Page 23 of 27, Line13(m)		($10,693,796)	($10,693,796)	($10,693,796)	($10,693,796)	($10,693,796)
22	Less: Proration Adjustment	Col (d) = Page 26 of 27, Line 40; Col (e) = Page 27 of 27, Line 40		$0	$0	($75,493)	($48,787)	$115
23	Net Deferred Tax Reserve	Line 20 + Line 21		$10,246,492	$10,382,725	$10,394,359	$10,462,891	$10,511,582
	Rate Base Calculation:							
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$37,144,770	$37,144,770	$37,144,770	$37,144,770	$37,144,770
25	Accumulated Depreciation	-Line 17		($739,732)	($2,219,195)	($3,698,659)	($5,178,122)	($6,657,586)
26	Deferred Tax Reserve	-Line 23		($10,246,492)	($10,382,725)	($10,394,359)	($10,462,891)	($10,511,582)
27	Year End Rate Base	Sum of Lines 24 through 26		$26,158,546	$24,542,850	$23,051,752	$21,503,756	$19,975,603
	Revenue Requirement Calculation:							
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$13,079,273	$25,350,698	$23,797,301	$22,277,754	$20,739,680
29	Pre-Tax ROR		3/	9.68%	9.68%	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,266,074	$2,453,948	$2,303,579	$2,156,487	$2,007,601
31	Book Depreciation	Line 16		$739,732	$1,479,463	$1,479,463	$1,479,463	$1,479,463
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$2,005,805**	**$3,933,411**	**$3,783,042**	**$3,635,950**	**$3,487,064**

1/ Actual Retirements

2/ Actual Cost of Removal

3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2016 Incremental Capital Investments

Line No.				Fiscal Year 2016 (a)	Fiscal Year 2017 (b)	Fiscal Year 2018 (c)	Fiscal Year 2019 (d)	Fiscal Year 2020 (e)
	Capital Repairs Deduction							
1	Plant Additions	Page 8 of 27, Line 3		$72,003,445				
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.67%				
3	Capital Repairs Deduction	Line 1 * Line 2		$21,361,075				
	Bonus Depreciation							
4	Plant Additions	Line 1		$72,003,445				
5	Less Capital Repairs Deduction	Line 3		$21,361,075				
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$50,642,370				
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		97.77%				
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$49,513,045				
9	Bonus Depreciation Rate (April 2015 - December 2015)	1 * 75% * 50%		37.50%				
10	Bonus Depreciation Rate (January 2016 - March 2016)	1 * 25% * 50%		12.50%				
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%				
12	Bonus Depreciation	Line 8 * Line 11		$24,756,523				
	Remaining Tax Depreciation							
13	Plant Additions	Line 1		$72,003,445				
14	Less Capital Repairs Deduction	Line 3		$21,361,075				
15	Less Bonus Depreciation	Line 12		$24,756,523				
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$25,885,847	$25,885,847	$25,885,847	$25,885,847	$25,885,847
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%
18	Remaining Tax Depreciation	Line 16 * Line 17		$970,719	$1,868,699	$1,728,398	$1,598,969	$1,478,858
19	FY16 Loss incurred due to retirements	Per Tax Department		$5,307,711				
20	Cost of Removal	Page 8 of 27, Line 10 + Line 10a		$8,173,099				
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$60,569,127	$1,868,699	$1,728,398	$1,598,969	$1,478,858

1/ Capital Repairs percentage is based on the actual results of the FY 2016 tax return.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2015 Actual Incremental Capital Investment

Line No.				Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)	Fiscal Year 2018 (d)	Fiscal Year 2019 (e)	Fiscal Year 2020 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*	Per RIPUC Docket No. 4473		$22,246,664	$0	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books		($268,138)	$0	$0	$0	$0	$0
	Discretionary Capital								
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4473		$54,410,377	$0	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books		($48,499)	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 1a + Line 2 + Line 2a		$76,340,403	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base								
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$76,340,403	$0	$0	$0	$0	$0
5	Retirements		1/	$15,666,095	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$60,674,308	$60,674,308	60,674,308	60,674,308	60,674,308	60,674,308
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$76,340,403	$0	$0	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant		$43,031,774	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$33,308,629	$33,308,629	$33,308,629	$33,308,629	$33,308,629	$33,308,629
10	Cost of Removal	Per RIPUC Docket No. 4473	2/	$6,988,398	$6,988,398	$6,988,398	$6,988,398	$6,988,398	$6,988,398
10a	Work Order Write Off Adjustment	Per Company's books		$22,398	$22,398	$22,398	$22,398	$22,398	$22,398
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**		**$40,319,425**	**$40,319,425**	**$40,319,425**	**$40,319,425**	**$40,319,425**	**$40,319,425**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
13	Vintage Year Tax Depreciation:								
14	2015 Spend	Page 11 of 27, Line 22		$71,871,022	$2,120,892	$1,961,656	$1,814,760	$1,678,440	$1,552,696
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$71,871,022	$73,991,914	75,953,570	77,768,330	79,446,770	80,999,466
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$1,031,463	$2,062,926	$2,062,926	$2,062,926	$2,062,926	$2,062,926
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,031,463	$3,094,390	$5,157,316	$7,220,243	$9,283,169	$11,346,096
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$70,839,559	$70,897,524	$ 70,796,254	$ 70,548,087	$ 70,163,601	$ 69,653,370
19	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$24,793,846	$24,814,134	$24,778,689	$24,691,831	$24,557,260	$24,378,680
21	Less: FY 2015 Federal NOL	Page 23 of 27, Line 13(l)		($8,148,936)	($8,148,936)	($8,148,936)	($8,148,936)	($8,148,936)	($8,148,936)
22	Less: Proration Adjustment	Col (e) = Page 26 of 27, Line 40; Col (f) = Page 27 of 27, Line 40		$0	$0	$0	$47,157	$73,061	$96,955
23	Net Deferred Tax Reserve	Line 20 + Line 21		$16,644,909	$16,665,197	$16,629,752	$16,590,051	$16,481,385	$16,326,699
	Rate Base Calculation:								
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$40,319,425	$40,319,425	$40,319,425	$40,319,425	$40,319,425	$40,319,425
25	Accumulated Depreciation	-Line 17		($1,031,463)	($3,094,390)	($5,157,316)	($7,220,243)	($9,283,169)	($11,346,096)
26	Deferred Tax Reserve	-Line 23		($16,644,909)	($16,665,197)	($16,629,752)	($16,590,051)	($16,481,385)	($16,326,699)
27	Year End Rate Base	Sum of Lines 24 through 26		$22,643,053	$20,559,839	$18,532,357	$16,509,131	$14,554,871	$12,646,631
	Revenue Requirement Calculation:								
28	Average Rate Base	Column (a) = Current Year Line 27 ÷ 2; Column (b) = (Prior Year Line 27 + Current Year Line 27) ÷ 2		$11,321,526	$21,601,446	$19,546,098	$17,520,744	$15,532,001	$13,600,751
29	Pre-Tax ROR		3/	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$1,095,924	$2,091,020	$1,892,062	$1,696,008	$1,503,498	$1,316,553
31	Book Depreciation	Line 16		$1,031,463	$2,062,926	$2,062,926	$2,062,926	$2,062,926	$2,062,926
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$2,127,387**	**$4,153,946**	**$3,954,989**	**$3,758,934**	**$3,566,424**	**$3,379,479**

1/ Actual Retirements

2/ Actual Cost of Removal

3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2015 Incremental Capital Investments

Line No.				Fiscal Year 2015 (a)	Fiscal Year 2016 (b)	Fiscal Year 2017 (c)	Fiscal Year 2018 (d)	Fiscal Year 2019 (e)	Fiscal Year 2020 (f)
	Capital Repairs Deduction								
1	Plant Additions	Page 10 of 27, Line 3		$76,340,403					
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.10%					
3	Capital Repairs Deduction	Line 1 * Line 2		$17,634,633					
	Bonus Depreciation								
4	Plant Additions	Line 1		$76,340,403					
5	Less Capital Repairs Deduction	Line 3		$17,634,633					
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$58,705,770					
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.91%					
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$58,652,935					
9	Bonus Depreciation Rate (April 2014 - December 2014)	1 * 75% * 50%		37.50%					
10	Bonus Depreciation Rate (January 2015 - March 2015)	1 * 25% * 50%		12.50%					
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%					
12	Bonus Depreciation	Line 8 * Line 11		$29,326,468					
	Remaining Tax Depreciation								
13	Plant Additions	Line 1		$76,340,403					
14	Less Capital Repairs Deduction	Line 3		$17,634,633					
15	Less Bonus Depreciation	Line 12		$29,326,468					
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$29,379,302	$29,379,302	$29,379,302	$29,379,302	$29,379,302	$29,379,302
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,101,724	$2,120,892	$1,961,656	$1,814,760	$ 1,678,440	$ 1,552,696
19	481(a) adjustment for partial retirements	Per Tax Department		$14,395,754					
20	FY15 Loss incurred due to retirements	Per Tax Department		$2,401,647					
21	Cost of Removal	Page 10 of 27, Line 10 + Line 10a		$7,010,796					
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18,19, 20, and 21		$71,871,022	$2,120,892	$1,961,656	$1,814,760	$1,678,440	$1,552,696

1/ Capital Repairs percentage is based on the actual results of the FY 2015 tax return.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2014 Actual Incremental Capital Investment

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)	Fiscal Year 2016 (c)	Fiscal Year 2017 (d)	Fiscal Year 2018 (e)	Fiscal Year 2019 (f)	Fiscal Year 2020 (g)
	Capital Investment Allowance									
1	*Non-Discretionary Capital*	Per RIPUC Docket No. 4382		$6,923,860	$0	$0	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books		($472,942)	$0	$0	$0	$0	$0	$0
	Discretionary Capital									
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Per RIPUC Docket No. 4382		$6,400,406	$0	$0	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books		($8,965)	$0	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 1a + Line 2 + Line 2a		$12,842,359	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base									
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$12,842,359	$0	$0	$0	$0	$0	$0
5	Retirements	Page 18 of 27, Line 9(c)	1/	($4,165,367)	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Column (b) = Prior Year Line 6		$17,007,726	17,007,726	17,007,726	17,007,726	17,007,726	17,007,726	17,007,726
	Change in Net Capital Included in Rate Base									
7	Capital Included in Rate Base	Line 3		$12,842,359	$0	$0	$0	$0	$0	$0
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant	2/	$7,173,397	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Column (b) = Prior Year Line 9		$5,668,962	$5,668,962	$5,668,962	$5,668,962	$5,668,962	$5,668,962	$5,668,962
10	Total Cost of Removal	Page 18 of 27, Line 6(c)		($887,841)	($887,841)	($887,841)	($887,841)	($887,841)	($887,841)	($887,841)
10a	Work Order Write Off Adjustment	Per Company's books		($37,062)	($37,062)	($37,062)	($37,062)	($37,062)	($37,062)	($37,062)
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**		**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**	**$4,744,059**
	Deferred Tax Calculation:									
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
13	Vintage Year Tax Depreciation:									
14	2014 Spend	Page 13 of 27, Line 20		$7,826,326	$306,845	$283,808	$262,555	$242,832	$224,640	$207,766
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$7,826,326	$8,133,171	$8,416,979	$8,679,534	$8,922,366	$9,147,006	$9,354,772
16	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Column (b) = Line 6 * Line 12		$289,131	$578,263	$578,263	$578,263	$578,263	$578,263	$578,263
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$289,131	$867,394	$1,445,657	$2,023,919	$2,602,182	$3,180,445	$3,758,708
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$7,537,194	$7,265,777	$6,971,322	$6,655,614	$6,320,184	$5,966,562	$5,596,064
19	Effective Tax Rate			35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$2,638,018	$2,543,022	$2,439,963	$2,329,465	$2,212,064	$2,088,297	$1,958,623
21	Less: FY 2014 Federal NOL	Page 23 of 27, Line 13(k)		($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)	($1,200,808)
22	Less: Proration Adjustment	Col (f) = Page 26 of 27, Line 40; Col (g) = Page 27 of 27, Line 40		$0	$0	$0	$0	$63,739	$67,196	$70,403
23	Net Deferred Tax Reserve	Line 20 + Line 21		$1,437,210	$1,342,214	$1,239,155	$1,128,657	$1,074,996	$954,685	$828,217
	Rate Base Calculation:									
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$4,744,059	$4,744,059	$4,744,059	$4,744,059	$4,744,059	$4,744,059	$4,744,059
25	Accumulated Depreciation	-Line 17		($289,131)	($867,394)	($1,445,657)	($2,023,919)	($2,602,182)	($3,180,445)	($3,758,708)
26	Deferred Tax Reserve	-Line 23		($1,437,210)	($1,342,214)	($1,239,155)	($1,128,657)	($1,074,996)	($954,685)	($828,217)
27	Year End Rate Base	Sum of Lines 24 through 26		$3,017,717	$2,534,451	$2,059,247	$1,591,482	$1,066,881	$608,929	$157,134
	Revenue Requirement Calculation:									
28	Average Rate Base	Col (a) = Line 27 * 23.23%; Col (b) = (Prior Year Line 27 + Current Year Line 27)/2	3/	$670,654	$2,776,084	$2,296,849	$1,825,365	$1,329,182	$837,905	$383,031
29	Pre-Tax ROR		4/	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
30	Return and Taxes	Line 28 * Line 29		$64,919	$268,725	$222,335	$176,695	$128,665	$81,109	$37,077
31	Book Depreciation	Line 16		$289,131	$578,263	$578,263	$578,263	$578,263	$578,263	$578,263
32	**Annual Revenue Requirement**	**Line 30 + Line 31**		**$354,051**	**$846,988**	**$800,598**	**$754,958**	**$706,927**	**$659,372**	**$615,340**

1/ Actual Retirements

2/ Depreciation Expense has been prorated for 2 months (February - March 2014)

3/ 23.23% per RIPUC Docket No. 4382 (FY 2014 Elec ISR reconciliation), Attachment WRR-1-Revised, Page 12.

4/ Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2014 Incremental Capital Investments

Line No.				Fiscal Year 2014 (a)	Fiscal Year 2015 (b)	Fiscal Year 2016 (c)	Fiscal Year 2017 (d)	Fiscal Year 2018 (e)	Fiscal Year 2019 (f)	Fiscal Year 2020 (g)
	Capital Repairs Deduction									
1	Plant Additions	Page 12 of 27, Line 3		$12,842,359						
2	Capital Repairs Deduction Rate	Per Tax Department	1/	34.46%						
3	Capital Repairs Deduction	Line 1 * Line 2		$4,425,477						
	Bonus Depreciation									
4	Plant Additions	Line 1		$12,842,359						
5	Less Capital Repairs Deduction	Line 3		$4,425,477						
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$8,416,882						
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		99.00%						
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$8,332,713						
9	Bonus Depreciation Rate (April 2013 - December 2013)	1 * 75% * 50%		37.50%						
10	Bonus Depreciation Rate (January 2014 - March 2014)	1 * 25% * 50%		12.50%						
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%						
12	Bonus Depreciation	Line 8 * Line 11		$4,166,357						
	Remaining Tax Depreciation									
13	Plant Additions	Line 1		$12,842,359						
14	Less Capital Repairs Deduction	Line 3		$4,425,477						
15	Less Bonus Depreciation	Line 12		$4,166,357						
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$4,250,525	$4,250,525	$4,250,525	$4,250,525	$4,250,525	$4,250,525	$4,250,525
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%
18	Remaining Tax Depreciation	Line 16 * Line 17		$159,395	$ 306,845	$ 283,808	$262,555	$242,832	$224,640	$207,766
19	Cost of Removal	Page 12 of 27, Line 10 + Line 10a		($924,903)						
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18 and 19		$7,826,326	$306,845	$283,808	$262,555	$242,832	$224,640	$207,766

1/ Capital Repairs percentage is based on the FY 2014 tax return.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2013 Actual Incremental Capital Investment

Line No.			Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)	Fiscal Year 2016 (d)	Fiscal Year 2017 (e)	Fiscal Year 2018 (f)	Fiscal Year 2019 (g)	Fiscal Year 2020 (h)
	Capital Additions Allowance									
	Non-Discretionary Capital									
1	Non-Discretionary Additions	Per RIPUC Docket No. 4307	($5,184,396)	$0	$0	$0	$0	$0	$0	$0
1a	Work Order Write Off Adjustment	Per Company's books	($576,955)	$0	$0	$0	$0	$0	$0	$0
	Discretionary Capital									
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending	Per RIPUC Docket No. 4307	($1,850,463)	$0	$0	$0	$0	$0	$0	$0
2a	Work Order Write Off Adjustment	Per Company's books	($207,197)	$0	$0	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 1a + Line 2 + Line 2a	($7,819,012)	$0	$0	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base									
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3	($7,819,012)	$0	$0	$0	$0	$0	$0	$0
5	Retirements		$5,838,935	$0	$0	$0	$0	$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	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)	($13,657,947)
	Change in Net Capital Included in Rate Base									
7	Capital Included in Rate Base	Line 3	($7,819,012)	$0	$0	$0	$0	$0	$0	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant	$0	$0	$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Column (a) = Line 7 - Line 8; Columns (b), (c) & (d) = Prior Year Line 9	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)	($7,819,012)
10	Total Cost of Removal		($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)	($1,895,059)
10a	Work Order Write Off Adjustment	Per Company's books	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)	($106,751)
11	**Total Net Plant in Service**	**Line 9 + Line 10 + Line 10a**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**	**($9,820,822)**
	Deferred Tax Calculation:									
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%	3.40%
13	Tax Depreciation	Page 15 of 27, Line 20	($6,531,672)	($246,695)	($228,173)	($211,087)	($195,230)	($180,604)	($167,038)	($154,530)
14	Cumulative Tax Depreciation	Prior Year Line 13 + Current Year Line 14	($6,531,672)	($6,778,367)	($7,006,540)	($7,217,627)	($7,412,857)	($7,593,461)	($7,760,499)	($7,915,029)
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Columns (b), (c) & (d) = Line 6 * Line 12	($232,185)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15	($232,185)	($696,555)	($1,160,925)	($1,625,296)	($2,089,666)	($2,554,036)	($3,018,406)	($3,482,776)
17	Cumulative Book / Tax Timer	Line 14 - Line 16	($6,299,487)	($6,081,812)	($5,845,615)	($5,592,331)	($5,323,191)	($5,039,425)	($4,742,093)	($4,432,253)
18	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18	($2,204,820)	($2,128,634)	($2,045,965)	($1,957,316)	($1,863,117)	($1,763,799)	($1,659,732)	($1,551,288)
20	Less: FY 2013 Federal NOL	Page 23 of 27, Line 13(j)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)	($2,342,381)
21	Less: Proration Adjustment	Col (g) = Page 26 of 27, Line 40; Col (h) = Page 27 of 27, Line 40	$0	$0	$0	$0	$0	($53,922)	($56,500)	($58,877)
22	Net Deferred Tax Reserve	Line 19 + Line 20	($4,547,202)	($4,471,016)	($4,388,347)	($4,299,697)	($4,205,498)	($4,160,102)	($4,058,614)	($3,952,547)
	Rate Base Calculation:									
23	Cumulative Incremental Capital Included in Rate Base	Line 11	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)	($9,820,822)
24	Accumulated Depreciation	-Line 16	$232,185	$696,555	$1,160,925	$1,625,296	$2,089,666	$2,554,036	$3,018,406	$3,482,776
25	Deferred Tax Reserve	-Line 22	$4,547,202	$4,471,016	$4,388,347	$4,299,697	$4,205,498	$4,160,102	$4,058,614	$3,952,547
26	Year End Rate Base	Sum of Lines 23 through 25	($5,041,435)	($4,653,251)	($4,271,550)	($3,895,829)	($3,525,658)	($3,106,684)	($2,743,802)	($2,385,499)
	Revenue Requirement Calculation:									
27	Average Rate Base	Column (a) = Current Year Line 26 ÷ 2; Column (b) = (Prior Year Line 26 + Current Year Line 26) ÷ 2	($2,520,717)	($4,847,343)	($4,462,400)	($4,083,689)	($3,710,743)	($3,316,171)	($2,925,243)	($2,564,650)
28	Pre-Tax ROR	1/	9.84%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
29	Return and Taxes	Line 27 * Line 28	($248,039)	($469,223)	($431,960)	($395,301)	($359,200)	($321,005)	($283,163)	($248,258)
30	Book Depreciation	Line 15	($232,185)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)	($464,370)
31	Property Taxes	Year 1 = $0, then Prior Year (Line 11 - Line 16) * Current Year Effective Property Tax rate 2/	$0	($350,952)	($374,039)	($324,300)	($284,593)	($289,520)	($252,342)	($236,217)
32	**Annual Revenue Requirement**	**Sum of Lines 29 through 31**	**($480,224)**	**($1,284,545)**	**($1,270,370)**	**($1,183,971)**	**($1,108,163)**	**($1,074,896)**	**($999,876)**	**($948,845)**

1/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

2/ FY 2017 effective property tax rate of 3.47% per Page 21 of 27, Line 71(h)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2013 Incremental Capital Investments

				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)	Fiscal Year 2015 (c)	Fiscal Year 2016 (d)	Fiscal Year 2017 (e)	Fiscal Year 2018 (f)	Fiscal Year 2019 (g)	Fiscal Year 2020 (h)
	Capital Repairs Deduction										
1	Plant Additions	Page 14 of 27, Line 3		($7,819,012)							
2	Capital Repairs Deduction Rate		1/	12.59%							
3	Capital Repairs Deduction	Line 1 * Line 2		($984,414)							
	Bonus Depreciation										
4	Plant Additions	Line 1		($7,819,012)							
5	Less Capital Repairs Deduction	Line 3		($984,414)							
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		($6,834,598)							
7	Percent of Plant Eligible for Bonus Depreciation			100.00%							
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		($6,834,598)							
9	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%		37.50%							
10	Bonus Depreciation Rate (January 2013 - March 2013)	1 * 25% * 50%		12.50%							
11	Total Bonus Depreciation Rate	Line 9 + Line 10		50.00%							
12	Bonus Depreciation	Line 8 * Line 11		($3,417,299)							
	Remaining Tax Depreciation										
13	Plant Additions	Line 1		($7,819,012)							
14	Less Capital Repairs Deduction	Line 3		($984,414)							
15	Less Bonus Depreciation	Line 12		($3,417,299)							
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)	($3,417,299)
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%
18	Remaining Tax Depreciation	Line 16 * Line 17		($128,149)	($246,695)	($228,173)	($211,087)	($195,230)	($180,604)	($167,038)	($154,530)
19	Cost of Removal	Page 14 of 27, Line 10 + Line 10a		($2,001,810)							
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19		($6,531,672)	($246,695)	($228,173)	($211,087)	($195,230)	($180,604)	($167,038)	($154,530)

1/ Capital Repairs percentage is based on the FY 2013 tax return.

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2019 Revenue Requirement on FY 2012 Actual Incremental Capital Investment

Line No.			Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)	Fiscal Year 2016 (e)	Fiscal Year 2017 (f)	Fiscal Year 2018 (g)	Fiscal Year 2019 (h)	Fiscal Year 2020 (i)
	Capital Additions Allowance										
	Non-Discretionary Capital										
1	Non-Discretionary	Per RIPUC Docket No. 4218	($4,019,686)	$0	$0	$0	$0	$0	$0	$0	$0
	Discretionary Capital										
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending	Per RIPUC Docket No. 4218	$4,163,942	$0	$0	$0	$0	$0	$0	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2	$144,256	$0	$0	$0	$0	$0	$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	$0	$0	$0	$0	$0
5	Retirements		$19,938	$0	$0	$0	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b) through (h) = Prior Year Line 6	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318	$124,318
	Change in Net Capital Included in Rate Base										
7	Incremental Capital Amount	Column (a) = Line 4, Columns (b) through (h) = Prior Year Line 7	$144,256	$144,256	$144,256	$144,256	$144,256	$144,256	$144,256	$144,256	$144,256
8	Cost of Removal		($771,131)	($771,131)	($771,131)	($771,131)	($771,131)	($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)**	**($626,875)**	**($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%	3.40%	3.40%	3.40%	3.40%	3.40%
11	Tax Depreciation	Page 17 of 27, Line 20	($654,965)	$2,107	$1,949	$1,803	$1,667	$1,542	$1,427	$1,320	$1,302
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11	($654,965)	($652,858)	($650,909)	($649,107)	($647,439)	($645,897)	($644,471)	($643,151)	($641,849)
13	Book Depreciation	Column (a) = -Line 6 * Line 10 * 50%; Columns (b) through (h)= Line 6 * Line 10	($2,113)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)	($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)	($19,021)	($23,247)	($27,474)	($31,701)	($35,928)
15	Cumulative Book / Tax Timer	Line 12 - Line 14	($652,852)	($646,518)	($640,342)	($634,313)	($628,419)	($622,650)	($616,996)	($611,450)	($605,921)
16	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
17	Deferred Tax Reserve	Line 15 * Line 16	($228,498)	($226,281)	($224,120)	($222,009)	($219,947)	($217,927)	($215,949)	($214,007)	($212,072)
18	Less: FY 2013 Federal NOL	Page 23 of 27, Line 13(i)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)	($3,434,992)
19	Less: Proration Adjustment	Col (h) = Page 26 of 27, Line 40; Col (i) = Page 27 of 27, Line 40	$0	$0	$0	$0	$0	$0	($1,074)	($1,054)	($1,051)
20	Net Deferred Tax Reserve	Line 17 + Line 18	($3,663,490)	($3,661,274)	($3,659,112)	($3,657,002)	($3,654,939)	($3,652,920)	($3,652,015)	($3,650,054)	($3,648,115)
	Rate Base Calculation:										
21	Cumulative Incremental Capital Included in Rate Base	Line 9	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)	($626,875)
22	Accumulated Depreciation	-Line 14	$2,113	$6,340	$10,567	$14,794	$19,021	$23,247	$27,474	$31,701	$35,928
23	Deferred Tax Reserve	-Line 20	$3,663,490	$3,661,274	$3,659,112	$3,657,002	$3,654,939	$3,652,920	$3,652,015	$3,650,054	$3,648,115
24	Year End Rate Base	Sum of Lines 21 through 23	$3,038,729	$3,040,739	$3,042,804	$3,044,921	$3,047,085	$3,049,292	$3,052,615	$3,054,880	$3,057,168
	Revenue Requirement Calculation:										
25	Average Rate Base	(Prior Year Line 24 + Current Year Line 24) ÷2	$1,519,364	$3,039,734	$3,041,771	$3,043,862	$3,046,003	$3,048,188	$3,050,953	$3,053,747	$3,056,024
26	Pre-Tax ROR	1/	9.30%	9.84%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%	9.68%
27	Return and Taxes	Line 25 * Line 26	$141,301	$299,110	$294,443	$294,646	$294,853	$295,065	$295,332	$295,603	$295,823
28	Book Depreciation	Line 13	($2,113)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)	($4,227)
29	Property Taxes	Year 1 = $0, then Prior Year (Line 9 - Line 14) * Current Year Effective Property Tax rate 2/	$0	($21,523)	($22,710)	($24,344)	($23,626)	($21,108)	($22,605)	($20,814)	($20,668)
30	**Annual Revenue Requirement**	**Sum of Lines 27 through 29**	**$139,188**	**$273,360**	**$267,506**	**$266,075**	**$267,000**	**$269,730**	**$268,500**	**$270,562**	**$270,928**

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%	4.96%	2.48%		2.48%
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%		7.17%	2.51%	9.68%

2/ FY 2017 effective property tax rate of 3.47% per Page 21 of 27, Line 71(h)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Incremental Capital Investments

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)	Fiscal Year 2015 (d)	Fiscal Year 2016 (e)	Fiscal Year 2017 (f)	Fiscal Year 2018 (g)	Fiscal Year 2019 (h)	Fiscal Year 2020 (i)
	Capital Repairs Deduction											
1	Plant Additions	Page 16 of 27, Line 3		$144,256								
2	Capital Repairs Deduction Rate	Per Tax Department	1/	21.05%								
3	Capital Repairs Deduction	Line 1 * Line 2		$30,366								
	Bonus Depreciation											
4	Plant Additions	Line 1		$144,256								
5	Less Capital Repairs Deduction	Line 3		$30,366								
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$113,890								
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	2/	85.00%								
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$96,807								
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		$84,706								
	Remaining Tax Depreciation											
13	Plant Additions	Line 1		$144,256								
14	Less Capital Repairs Deduction	Line 3		$30,366								
15	Less Bonus Depreciation	Line 12		$84,706								
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$29,184	$29,184	$29,184	$29,184	$29,184	$29,184	$29,184	$29,184	$29,184
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,094	$2,107	$1,949	$1,803	$1,667	$1,542	$1,427	$1,320	$1,302
19	Cost of Removal	Page 16 of 27, Line 8		($771,131)								
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19		($654,965)	$2,107	$1,949	$1,803	$1,667	$1,542	$1,427	$1,320	$1,302

1/ Per Docket 4307 FY 2013 Electric ISR Reconciliation Filing at Attachment WRR-1, Page 8, Line 2
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
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2012 - 2014 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Actual Fiscal Year 2013 (b)	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 Reconciliation Filing Docket No. 4307; Col (c) = FY 2014 ISR Reconcilation Filing Docket No. 4382	$48,946,456	$44,331,141	$56,129,551
1a	Work Order Write Off Adjustment	Per Company's books	$0	($784,153)	($481,907)
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
3	Incremental ISR Capital Investment	Line 1 + Line 1a - Line 2	$144,256	($7,819,353)	$12,842,360
	Cost of Removal				
4	ISR - Eligible Cost of Removal	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b)= FY 2013 Reconciliation Filing Docket No. 4307; Col (c) = FY 2014 ISR Reconciliation Filing Docket No. 4382	$5,807,869	5,179,941	$5,007,992
4a	Work Order Write Off Adjustment	Per Company's books	$0	($106,751)	($37,062)
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); Line Note 3(e)	$6,579,000	$7,075,000	$5,895,833
6	Incremental Cost of Removal	Line 4 + Line 4a - Line 5	($771,131)	($2,001,810)	($924,903)
	Retirements				
7	ISR - Eligible Retirements/Actual	Col (a)= FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) = FY 2013 ISR Reconciliation Filing Docket No. 4307; Col (c) = FY 2014 ISR Reconciliation Filing Docket No. 4382	$7,740,446	$14,255,714	$3,299,874
8	ISR - Eligible Retirements/Estimated	Col (a)= FY 2012 ISR Proposal Filing Docket No. 4218; Col (b)= FY 2013 ISR Proposal Filing Docket No. 4307; Col (c) = Line 2 (c) * 17.44% Retirement rate per Docket 4323 (Workpaper MDL-19-ELEC Page 3)	$7,720,508	$8,416,779	$7,465,242
9	Incremental Retirements	Line 7 - Line 8	$19,938	$5,838,935	($4,165,367)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2017 Capital Investment

Line No.	Discretionary Capital		Actuals (a)
1	Cumulative FY 2016 Discretionary Capital **ADDITIONS**	Docket No. 4539 FY16 Reconciliation Att. AST-1 Page 14, Line 3	$159,030,344
2	FY 2017 Discretionary Capital **ADDITIONS**	Attachment PSA-1, Page 3, Table 1	$46,895,663
3	Cumulative Actual Discretionary Capital Additions	Line 1 + Line 2	$205,926,007
4	Cumulative FY 2016 Discretionary Capital **SPENDING**	Docket No. 4539 FY16 Reconciliation Att. AST-1 Page 14, Line 6	$192,056,464
5	FY 2017 Discretionary Capital **SPENDING**	Attachment PSA-1, Page 5, Table 3	$48,266,492
6	Cumulative Actual Discretionary Capital Spending	Line 4 + Line 5	$240,322,956
			As Approved in Docket No. 4592
7	Cumulative FY 2016 Approved Discretionary Capital **SPENDING**	Docket No. 4539 FY16 Reconciliation Att. AST-1 Page 14, Line 9	$174,212,150
8	FY 2017 Approved Discretionary Capital **SPENDING**	Attachment PSA-1, Page 5, Table 3	$52,523,386
9	Cumulative Actual Approved Discretionary Capital Spending	Line 7 + Line 8	$226,735,536
			Total Allowed
10	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 3, Line 6, or Line 9	$205,926,007
11	Prior Year Cumulative Allowed Disretionary Capital Included in Rate Base	Docket No. 4539 FY16 Reconciliation Filing Att. AST-1, Page 14, Line 10	$159,030,344
12	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 10 - Line 11	**$46,895,663**

The Narragansett Electric Company
d/b/a National Grid
FY 2019 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)			
		RY End	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2014			
1	Plant In Service	$1,358,470	###### ###	$1,885	$11,160		$550		$1,370,180			
2												
3	Accumulated Depr	$611,570				$7,498	$550	($828)	$618,789			
4												
5	Net Plant	$746,900							$751,391			
6												
7	Property Tax Expense	$29,743							$27,502			
8												
9	Effective Prop tax Rate	3.98%							3.66%			
10												
11												
12	**Effective tax Rate Calculation**	End of FY 2014	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2015			
13												
14	Plant In Service	$1,370,180	$76,340	$5,801	$82,141		($15,666)		$1,436,655			
15												
16	Accumulated Depr	$618,789				$46,514	($15,666)	($6,988)	$642,649			
17												
18	Net Plant	$751,391							$794,006			
19												
20	Property Tax Expense	$27,502							$32,549			
21												
22	Effective Prop tax Rate	3.66%							4.10%			
23												
24	**Effective tax Rate Calculation**	End of FY 2015	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2016			
25												
26	Plant In Service	$1,436,655	$72,003	$17,773	$89,777		($28,490)		$1,497,942			
27												
28	Accumulated Depr	$642,649				$48,686	($28,490)	($8,193)	$654,652			
29												
30	Net Plant	$794,006							$843,290			
31												
32	Property Tax Expense	$32,549							$31,580			
33												
34	Effective Prop tax Rate	4.10%							3.74%			
35												
36		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
37	**Property Tax Recovery Calculation**											
38		**Cumulative Increm. ISR Prop. Tax for FY14**				**Cumulative Increm. ISR Prop. Tax for FY15**				**Cumulative Increm. ISR Prop. Tax for FY16**		
39			2 mos									
40	ISR Additions		$9,275				$76,340				$72,003	
41	Book Depreciation: base allowance on ISR eligible plant		($7,173)				($43,032)				($43,032)	
42	Book Depreciation: current year ISR additions		($324)				($1,031)				($740)	
43	COR		$828				$6,988				$8,193	
44												
45	Net Plant Additions		$2,605				$39,266				$36,425	
46												
47	RY Effective Tax Rate		3.98%				3.98%				3.98%	
48	ISR Property Tax Recovery on FY 2014 vintage investment			$104				$102				$89
49	ISR Property Tax Recovery on FY 2015 vintage investment							$1,564				$1,523
50	ISR Property Tax Recovery on FY 2016 vintage investment											$1,451
51												
52												
53	ISR Year Effective Tax Rate	3.66%				4.10%				3.74%		
54	RY Effective Tax Rate	3.98%	-0.32%			3.98%	0.12%			3.98%	-0.24%	
55	RY Effective Tax Rate 2 mos for FY 2014		-0.05%									
56	RY Net Plant times 2 mo rate	$746,900	-0.05%	($401)		$746,900	* 0.12%	$875		$746,900	* -0.24%	($1,773)
57	FY 2014 Net Adds times ISR Year Effective Tax rate	$2,605	-0.32%	($8)		$2,568	* 0.12%	$3		$2,234	* -0.24%	($5)
58	FY 2015 Net Adds times ISR Year Effective Tax rate					$39,266	* 0.12%	$46		$38,234	* -0.24%	($91)
59	FY 2016 Net Adds times ISR Year Effective Tax rate									$36,425	* -0.24%	($86)
60	Total Property Tax due to rate differential			($409)				$924				($1,869)
61												
62	Total ISR Property Tax Recovery			($306)				$2,590				$1,193
62a	As Approved in RIPUC Docket No. 4539			($304)				$2,590				$1,192
62b	Work Order Write Off Adjustment			(2)				(0)				2

The Narragansett Electric Company
d/b/a National Grid
FY 2019 ISR Property Tax Recovery Adjustment (continued)
(000s)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**End of FY 2016**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2017**
63	Plant In Service	$1,497,942	$75,489	$10,718	$86,207		($22,245)		$1,561,904
64									
65	Accumulated Depr	$654,652				$50,815	($22,245)	($7,807)	$675,416
66									
67	Net Plant	$843,290							$886,489
68									
69	Property Tax Expense	$31,580							$30,784
70									
71	Effective Prop tax Rate	3.74%							3.47%
72									
73	**Effective tax Rate Calculation**	**End of FY 2017**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2018**
74									
75	Plant In Service	1,561,904	74,843	3,100	77,943		(16,457)		1,623,390
76									
77	Accumulated Depr	675,416				52,948	(16,457)	(9,646)	702,260
78									
79	Net Plant	886,489							921,129
80									
81	Property Tax Expense	30,784							34,495
82									
83	Effective Prop tax Rate	3.47%							3.74%
84									
85	**Effective tax Rate Calculation**	**End of FY 2018**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2019**
86									
87	Plant In Service	1,623,390	91,337	3,100	94,437		(27,264)		1,690,563
88									
89	Accumulated Depr	702,260				55,135	(27,264)	(12,054)	718,077
90									
91	Net Plant	921,129							972,485
92									
93	Property Tax Expense	34,495							33,770
94									
95	Effective Prop tax Rate	3.74%							3.47%
96									

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
97												
98	**Property Tax Recovery Calculation**											
99		**Cumulative Increm. ISR Prop. Tax for FY17**				**Cumulative Increm. ISR Prop. Tax for FY18**				**Cumulative Increm. ISR Prop. Tax for FY19**		
100												
101	ISR Additions		$75,489				$74,843				$91,337	
102	Book Depreciation: base allowance on ISR eligible plant		($43,032)				($43,032)				($43,032)	
103	Book Depreciation: current year ISR additions		($905)				($993)				($1,089)	
104	COR		$7,807				$9,646				$12,054	
105												
106	Net Plant Additions		$39,359				$40,465				$59,270	
107												
108	RY Effective Tax Rate		3.98%				3.98%				3.98%	
109	ISR Property Tax Recovery on FY 2014 vintage investment			$76				$62				$49
110	ISR Property Tax Recovery on FY 2015 vintage investment			$1,440				$1,358				$1,276
111	ISR Property Tax Recovery on FY 2016 vintage investment			$1,392				$1,333				$1,274
112	ISR Property Tax Recovery on FY 2017 vintage investment			$1,567				$1,495				$1,423
113	ISR Property Tax Recovery on FY 2018 vintage investment							$1,611				$1,532
114	ISR Property Tax Recovery on FY 2019 vintage investment											$2,360
115	Subtotal			$4,475				$5,860				$7,915
116	ISR Year Effective Tax Rate	3.47%				3.74%				3.47%		
117	RY Effective Tax Rate	3.98%	-0.51%			3.98%	-0.24%			3.98%	-0.51%	
118	RY Effective Tax Rate 2 mos for FY 2014											
119	RY Net Plant times 2 mo rate	$746,900	* -0.51%	($3,807)		$746,900	* -0.24%	($1,773)		$746,900	* -0.51%	($3,807)
120	FY 2014 Net Adds times ISR Year Effective Tax rate	$1,900	* -0.51%	($10)		$1,566	* -0.24%	($4)		$1,232	* -0.51%	($6)
121	FY 2015 Net Adds times ISR Year Effective Tax rate	$36,171	* -0.51%	($184)		$34,108	* -0.24%	($81)		$32,045	* -0.51%	($163)
122	FY 2016 Net Adds times ISR Year Effective Tax rate	$34,945	* -0.51%	($178)		$33,466	* -0.24%	($79)		$31,987	* -0.51%	($163)
123	FY 2017 Net Adds times ISR Year Effective Tax rate	$39,359	* -0.51%	($201)		$37,549	* -0.24%	($89)		$35,739	* -0.51%	($182)
124	FY 2018 Net Adds times ISR Year Effective Tax rate					$40,465	* -0.24%	($96)		$38,480	* -0.51%	($196)
125	FY 2019 Net Adds times ISR Year Effective Tax rate									59,270	* -0.51%	($302)
126	Total Property Tax due to rate differential			($4,379)				($2,122)				($4,820)
127												
128	Total ISR Property Tax Recovery			$96				$3,738				$3,095

The Narragansett Electric Company
d/b/a National Grid
FY 2019 ISR Property Tax Recovery Adjustment (continued)
(000s)

Line Notes	
1(a)-9(a)	Per Rate Year cost of service
1(b) - 9(h)	Per FY 2014 Electric ISR Reconciliation Filing per Docket 4382
14(a)-22(h)	Per FY 2015 Electric ISR Reconciliation Filing per Docket 4473
26(a)-34(h)	Per FY 2016 Electric ISR Reconciliation Filing per Docket 4539
40(a) - 62(c)	Per FY 2017 Electric ISR Reconciliation Filing per Docket 4382
40(e)-62(g)	Per FY 2015 Electric ISR Reconciliation Filing per Docket 4473
40(i)-62(k)	Per FY 2016 Electric ISR Reconciliation Filing per Docket 4539
63(a)	Per Line 26(h)
63(b)	Per Page 7 of 27, Line 1 /1000
63(c)	Per Company's books
63(d)	Line 63(b) + Line 63(c)
63(f)	Per Page 6 of 27, Line 5 /1000
63(h)	Line 63(a) + Line 63(d) + Line 63(f)
65(a)	Per Line 28(h)
65(e)	Rate Year depr allowance of $44,986 * (Line 1(d)+1(f) * comp depr rate of 3.40%) + (Line 14(d)+14(f) * comp depr rate of 3.40%) + (Line 26(d)+26(f) * comp depr rate of 3.40%) + (Line 63(d) +63(f) * comp depr rate of 3.40% * 50%)
65(f)	Per Line 63(f)
65(g)	Per Page 6 of 27, Line 10/ 1000
65(h)	Line 65(a) + Line 65(e) + Line 65(f) + Line 65(g)
67(a)	Per Line 30(h)
67(h)	Line 63(h) - Line 65(h)
69(a)	Per Line 32(h)
69(h)	Per Company's books
71(a)	Per Line 34(h)
71(h)	Line 69(h) / Line 67(h)
75(a)	Per Line 63(h)
75(b)	Per Page 5 of 27, Line 5(a) /1000
75(d)	Sum of Line 75(b) and Line 75(c)
75(f)	Per Page 4 of 27, Line 5(a) /1000
75(h)	Line 75(a) + Line 75(d) + 75(f)
77(a)	Per Line 65(h)
77(e)	Rate Year depr allowance of $44,986 * (Line 1(d)+1(f)* comp depr rate of 3.40%) + (Line 14(d)+14(f)* comp depr rate of 3.40%) + (Line , 26(d)+26(f)*comp depr rate of 3.40%) + (Line 63(d) +63(f)*comp depr rate of 3.40%)+ (Line 75(d) +75(f)*comp depr rate of 3.40%*50%)
77(f)	Per Line 75(f)
77(g)	Per Page 6 of 27, Line 11(a) /1000
77(h)	Line 77(a) + Line 77(e) + Line 77(f) + Line 77(g)
79(a)	Per Line 67(h)
79(h)	Line 75(h) - Line 77(h)
81(a)	Line 69(h)
81(h)	Line 79(h) * Line 83(h)
83(a)	Line 81(a)/Line 79(a)
83(h)	Per Line 34(h)
87(a)	Per Line 75(h)
87(b)	Per Page 3 of 27, Line 1(a) /1000
87(d)	Line 87(b) + Line 87(c)
87(f)	Per Page 2 of 27, Line 5(a) /1000
89(a)	Per Line 77(h)
89(f)	Per Line 87(f)
89(g)	Per Page 2 of 27, Line 10(a) /1000
89(h)	Line 89(a) + Line 89(e) + Line 89(f) + Line 89(g)
91(a)	Per Line 79(h)
91(h)	Line 87(h) - Line 89(h)
93(a)	Per Line 81(h)
95(a)	Line 93(a) / Line 91 (a)
95(h)	Per Line 71(h)
101(b)	Per Line 63(b)
101(f)	Per Line 75(b)
101(j)	Per Line 87(b)
102(b)	Per Page 6 of 27, Line 8/ 1000
102(f)	Per Page 4 of 27, Line 8(a) /1000
102(i)	Per Page 2 of 27, Line 8(a) /1000
103(b)	Per Page 6 of 27, Line 15/ 1000
103(f)	Per Page 4 of 27, Line 16(a) /1000
103(j)	Per Page 2 of 27, Line 16(a) /1000
104(b)	Per Line 65(g) *-1
104(f)	Per Line 77(g) * -1
104(j)	Per Line 89(g) * -1
106(b)	Sum of Lines 101(b) through Lines 104(b)
106(f)	Sum of Lines 101(f) through Lines 104(f)
106(j)	Sum of Lines 101(j) through Lines 104(j)
108(b)	Per Line 9(a)
108(f)	Per Line 9(a)
108(j)	Per Line 9(a)
109(c)	Line 108(b) * Line 120(a)
109(g)	Line 108(f)* Line 120(e)
109(k)	Line 108(j) * Line 120(i)
110(c)	Line 108(b) * Line 121(a)
110(g)	Line 108(f)* Line 121(e)
110(k)	Line 108(j) * Line 121(i)
111(c)	Line 108(b) * Line 122(a)
111(g)	Line 108(f) * Line 122(e)
111(k)	Line 108(j) * Line 122(i)
112(c)	Line 108(b) * Line 123(a)
112(g)	Line 108(f) * Line 123(e)
112(k)	Line 108(j) * Line 123(i)

Line Notes	
113(g)	Line 108(f) * Line 124(e)
113(k)	Line 108(j) * Line 124(i)
114(k)	Line 108(j) * Line 125(i)
115(c)	Sum of Lines 109(c) through Lines 114(c)
115(g)	Sum of Lines 109(g) through Lines 114(g)
115(k)	Sum of Lines 109(k) through Lines 114(k)
116(a)	Per Line 71(h)
116(e)	Per Line 83(h)
116(i)	Per Line 95(h)
117(a)	Per Line 9(a)
117(b)	Line 116(a)-Line 117(a)
117(e)	Per Line 9(a)
117(f)	Line 116(e)-Line 117(e)
117(i)	Per Line 9(a)
117(j)	Line 116(i)-Line 117(i)
119(a)	Per Line 5(a)
119(b)	Per Line 117(b)
119(c)	Line 119(a) * Line 117(b)
119(e)	Per Line 5(a)
119(f)	Per Line 117(f)
119(g)	Line 119(e) * Line 117(f)
119(i)	Per Line 5(a)
119(j)	Per Line 117(j)
119(k)	Line 119(i) * Line 117(j)
120(a)	Line 57(i) - ((Line 40(b)+Line 1(f))*3.40%)
120(b)	Per Line 117(b)
120(c)	Line 120(a) * Line 117(b)
120(e)	Line 120(e) * Line 117(b)
120(f)	Per Line 117(f)
120(g)	Line 120(e) * Line 117(f)
120(i)	Line 120(e) - ((Line 40(b)+Line 1(f))*3.40%)
120(j)	Per Line 117(j)
120(k)	Line 120(i) * 117(j)
121(a)	Line 58(i) - ((Line 40(f)+Line 14(f))*3.40%)
121(b)	Per Line 117(b)
121(c)	Line 121(a) * Line 117(b)
121(e)	Line 121(a) - ((Line 40(f)+Line 1(f))*3.40%)
121(f)	Per Line 117(f)
121(g)	Line 121(e) * Line 117(f)
121(i)	Line 121(e) - ((Line 40(f)+Line 14(f))*3.40%)
121(j)	Per Line 117(j)
121(k)	Line 121(i) * 117(j)
122(a)	Line 59(i) - ((Line 40(j)+Line 26(f))*3.40%)
122(b)	Per Line 117(b)
122(c)	Line 122(a) * Line 117(b)
122(e)	Line 122(a) - ((Line 40(j)+Line 26(f))*3.40%)
122(f)	Per Line 117(f)
122(g)	Line 122(e) * Line 117(f)
122(i)	Line 122(e) - ((Line 40(j)+Line 26(f))*3.40%)
122(j)	Per Line 117(j)
122(k)	Line 122(i) * Line 117(j)
123(a)	Per Line 106(b)
123(b)	Per Line 117(b)
123(c)	Line 123(a) * Line 117(b)
123(e)	Line 123(a) - ((Line 101(b)+Line 63(f))*3.40%)
123(f)	Per Line 117(f)
123(g)	Line 123(e) * Line 117(f)
123(i)	Line 123(e) - ((Line 101(b)+Line 63(f))*3.40%)
123(j)	Per Line 117(j)
123(k)	Line 123(i) * Line 117(j)
124(e)	Per Line 106(f)
124(f)	Per Line 117(f)
124(g)	Line 124(e) * 117(f)
124(i)	Line 124(e) - ((Line 101(f)+Line 75(f))*3.40%)
124(j)	Per Line 117(j)
124(k)	Line 124(i) * Line 117(j)
125(i)	Per Line 106(j)
125(j)	Per Line 117(j)
125(k)	Line 117(j) * Line 125(i)
126(c)	Sum of Lines 119(c) through Lines 125(c)
126(g)	Sum of Lines 119(g) through Lines 125(g)
126(k)	Sum of Lines 119(k) through Lines 125(k)
128(c)	Line 115(c) + Line 126(c)
128(g)	Line 115(g) + Line 126(g)
128(k)	Line 115(k) + Line 126(k)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Total Base Rate Plant DIT Provision								
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
2	Total Base Rate Plant DIT Provision								
3	Incremental FY 12	($228,498)	($226,281)	($224,120)	($222,009)	($219,947)	($217,927)	($215,949)	($214,007)
4	Incremental FY 13		($2,013,121)	($1,937,607)	($2,045,965)	($1,957,316)	($1,863,117)	($1,763,799)	($1,659,732)
5	Incremental FY 14			$2,763,058	$2,543,022	$2,439,963	$2,329,465	$2,212,064	$2,088,297
6	FY 2015				$24,793,846	$24,814,134	$24,778,689	$24,691,831	$24,557,260
7	FY 2016					$20,940,288	$21,076,521	$21,163,648	$21,205,475
8	FY 2017						$20,132,244	$20,243,200	$20,298,253
9	FY 2018							$19,606,374	$19,679,140
10	FY 2019								$23,307,872
11	TOTAL Plant DIT Provision	($228,498)	($2,239,403)	$601,331	$25,068,893	$46,017,122	$66,235,874	$85,937,369	$109,262,558
12	Distribution-related NOL								
13	Lesser of Distribution-related NOL or DIT Provision								
14	Total NOL								
15	NOL recovered in transmission rates								
16	Distribution-related NOL								

		(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		CY 2011	CY 2012	Jan-2013	Feb 13 - Jan 14				
1	Total Base Rate Plant DIT Provision	$15,856,458	$5,546,827	$521,151	($1,967,911)				
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
2	Total Base Rate Plant DIT Provision	$13,279,050	$4,353,286	($1,639,926)	$0	$0	$0	$0	$0
3	Incremental FY 12	($228,498)	$2,217	$2,161	$2,110	$2,063	$2,019	$1,979	$1,941
4	Incremental FY 13		($2,013,121)	$75,514	($108,358)	$88,649	$94,199	$99,318	$104,066
5	Incremental FY 14			$2,763,058	($220,036)	($103,059)	($110,498)	($117,401)	($123,768)
6	FY 2015				$24,793,846	$20,288	($35,445)	($86,858)	($134,570)
7	FY 2016					$20,940,288	$136,232	$87,127	$41,827
8	FY 2017						$20,132,244	$110,955	$55,054
9	FY 2018							$19,606,374	$72,766
10	FY 2019								$23,307,872
11	TOTAL Plant DIT Provision	$13,050,552	$2,342,381	$1,200,808	$24,467,561	$20,948,229	$20,218,752	$19,701,494	$23,325,189
12	Distribution-related NOL	$3,434,992	$8,552,548	$13,179,356	$8,148,936	$10,693,796	$0	$0	$0
13	Lesser of Distribution-related NOL or DIT Provision	$3,434,992	$2,342,381	$1,200,808	$8,148,936	$10,693,796	$0	$0	$0
14	Total NOL	$4,310,461	$11,442,811	$19,452,677	$12,108,052	$16,267,471	$0	$0	$0
15	NOL recovered in transmission rates	$875,468	$2,890,262	$6,273,321	$3,959,116	$5,573,675	$0	$0	$0
16	Distribution-related NOL	$3,434,992	$8,552,548	$13,179,356	$8,148,936	$10,693,796	$0	$0	$0

1(g) Per Dkt 4323 Compliance filing Attachment 1, Page 64 of 71, Line 19(e) less Line 19(a)
1(h)-1(j) Per Dkt 4323 Compliance filing Attachment 1, Page 70 of 71, Lines 32, 42, and 48
3(a)-9(f) ADIT per vintage year ISR revenue requirement calculations
3(g) -8(l) Year over year change in ADIT shown in Cols (a) through (e)
9 Sum of Lines 2 through 8
10 Line 14
11 Lesser of Line 9 or 10
12 Per Tax Department
13 Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 12
14 Line 12 - Line 13

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
True-Up for FY 2012 through FY 2014 Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)
		Revenue Requirement Year					
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
1	Return on Rate Base	9.30%	9.84%	9.68%	9.68%	9.68%	9.68%
		Vintage Capital Investment Year					
		FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
2	Lesser of NOL or DIT Provision	$ 4,310,461	$ 2,342,381	$ 1,200,808	$ 12,108,052	$ 10,200,749	$ -
	Revenue Requirement Increase due to NOL						
		Revenue Requirement Year					
	Vintage Capital Investment Year	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
3	FY 2012	$ 200,436	$ 424,149	$ 417,253	$ 417,253	$ 417,253	$ 417,253
4	FY 2013	$ -	$ 115,245	$ 226,743	$ 226,743	$ 226,743	$ 226,743
5	FY 2014	$ -	$ -	$ 27,000	$ 116,238	$ 116,238	$ 116,238
6	FY 2015	$ -	$ -	$ -	$ 586,030	$ 1,172,059	$ 1,172,059
7	FY 2016	$ -	$ -	$ -	$ -	$ 493,716	$ 987,432
8	FY 2017	$ -	$ -	$ -	$ -	$ -	$ -
9	TOTAL	**$ 200,436**	**$ 539,395**	**$ 670,996**	**$ 1,346,263**	**$ 2,426,009**	**$ 2,919,725**
10	**Total FY 2012 through FY 2014 revenue requirement impact to be recovered over three years**						**$ 1,410,826**
11	**Recovery per year**						**$ 470,275**

1(a) Per Docket No. 4065
1(b)-(c) Per vintage year revenue requirement calculations at Page 14 of 27, and Page 12 of 27, respectively
2 FY2015 Revenue Requirement Reconciliation R.I.P.U.C. Docket No. 4473
3 Line 2(a) * Line 1(a) * 50%; Line 2(a) * Line 1(b); Line 2(a) * Line 1(c); Line 2(a) * Line 1(d); Line 2(a) * Line 1(e); Line 2(a) * Line 1(f)
4 Line 2(b) * Line 1(b) * 50%; Line 2(b) * Line 1(c); Line 2(b) * Line 1(d); Line 2(b) * Line 1(e); Line 2(b) * Line 1(f)
5 Line 2(c) * Line 1(c) * 23.23%; Line 2(c) * Line 1(d); Line 2(c) * Line 1(e); Line 2(c) * Line 1(f)
6 Line 2(d) * Line 1(d) * 50%; Line 2(d) * Line 1(e); Line 2(d) * Line 1(f)
7 Line 2(e) * Line 1(e) * 50%; Line 2(e) * Line 1(f)
8 Line 2(f) * Line 1(f) * 50%
9 Sum of Lines 3 through 8
10 Line 9(a) + Line 9(b) + Line 9(c)
11 Line 10(f) / 3

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of FY 2018 Net Deferred Tax Reserve Proration

Line No.	Deferred Tax Subject to Proration		(a)=Sum of (b) through (h) Total	(b) Vintage Year 2018	(c) Vintage Year 2017	(d) Vintage Year 2016	(e) Vintage Year 2015	(f) Vintage Year 2014	(g) Vintage Year 2013	(h) Vintage Year 2012
1	Book Depreciation	Col (b) = Page 2 of 27, Line 16; Col (c) = Page 4 of 27, Line 16; Col (d) = Page 6 of 27, Line 15; Col (e) = Page 8 of 27, Line 16; Col (f) = Page 10 of 27, Line 16; Col (g) = Page 12 of 27, Line 16; Col (h) = Page 14 of 27, Line 15; Col (i) = Page 16 of 27, Line 13	$6,767,472	$992,555	$2,122,861	$1,479,463	$2,062,926	$578,263	($464,370)	($4,227)
2	Bonus Depreciation	Page 3 of 27, Line 12	($26,966,349)	($26,966,349)	$0	$0	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (b) = Page 3 of 27, Line 18; Col (c) = Page 5 of 27, Line 18; Col (d) = Page 7 of 27, Line 18; Col (e) = Page 9 of 27, Line 18; Col (f) = Page 11 of 27, Line 18; Col (g) = Page 13 of 27, Line 18; Col (h) = Page 15 of 27, Line 18; Col (i) = Page 17 of 27, Line 18	($7,105,894)	($1,139,188)	($2,211,545)	($1,876,746)	$ (1,814,760)	($242,832)	$180,604	($1,427)
4	FY 2018 tax (gain)/loss on retirements	Page 3 of 27, Line 19	($1,760,937)	($1,760,937)	$0	$0	$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($29,065,708)	($28,873,919)	($88,684)	($397,283)	$248,166	$335,430	($283,766)	($5,653)
6	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($10,172,998)	($10,105,872)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
	Deferred Tax Not Subject to Proration									
8	Capital Repairs Deduction	Page 3 of 27, Line 3	($17,498,293)	($17,498,293)						
9	Cost of Removal	Page 3 of 27, Line 20	($9,646,000)	($9,646,000)						
10	Book/Tax Depreciation Timing Difference at 3/31/2017		$0	$0						
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($27,144,293)	($27,144,293)						
12	Effective Tax Rate		35.00%	35.00%						
13	Deferred Tax Reserve	Line 11 * Line 12	($9,500,503)	($9,500,503)						
14	Total Deferred Tax Reserve	Line 7 + Line 13	($19,673,500)	($19,606,374)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
15	Net Operating Loss	Page 2 of 27, Line 21	$0	$0						
16	Net Deferred Tax Reserve	Line 14 + Line 15	($19,673,500)	($19,606,374)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
	Allocation of FY 2018 Estimated Federal NOL									
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($28,873,919)	($28,873,919)						
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($27,144,293)	($27,144,293)						
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($56,018,212)	($56,018,212)						
20	Total FY 2018 Federal NOL	(Page 2 of 27, Line 21) / 35%	$0	$0						
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0						
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0						
23	Effective Tax Rate		35.00%	35.00%						
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0						
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($10,172,998)	($10,105,872)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)

Line No.	Proration Calculation	(i) Number of Days in Month	(j) Proration Percentage	(k)= Sum of (l) through (r)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
26	April 2017	30	91.78%	($778,072)	($772,938)	($2,374)	($10,635)	$6,643	$8,979	($7,596)	($151)
27	May 2017	31	83.29%	($706,071)	($701,412)	($2,154)	($9,651)	$6,029	$8,148	($6,893)	($137)
28	June 2017	30	75.07%	($636,393)	($632,194)	($1,942)	($8,698)	$5,434	$7,344	($6,213)	($124)
29	July 2017	31	66.58%	($564,392)	($560,668)	($1,722)	($7,714)	$4,819	$6,513	($5,510)	($110)
30	August 2017	31	58.08%	($492,392)	($489,143)	($1,502)	($6,730)	$4,204	$5,682	($4,807)	($96)
31	September 2017	30	49.86%	($422,714)	($419,924)	($1,290)	($5,778)	$3,609	$4,878	($4,127)	($82)
32	October 2017	31	41.37%	($350,713)	($348,399)	($1,070)	($4,794)	$2,994	$4,047	($3,424)	($68)
33	November 2017	30	33.15%	($281,035)	($279,180)	($857)	($3,841)	$2,400	$3,243	($2,744)	($55)
34	December 2017	31	24.66%	($209,034)	($207,655)	($638)	($2,857)	$1,785	$2,412	($2,041)	($41)
35	January 2018	31	16.16%	($137,034)	($136,129)	($418)	($1,873)	$1,170	$1,581	($1,338)	($27)
36	February 2018	28	8.49%	($72,001)	($71,526)	($220)	($984)	$615	$831	($703)	($14)
37	March 2018	31	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
38	Total	365		($4,649,850)	($4,619,168)	($14,187)	($63,556)	$39,701	$53,661	($45,396)	($904)
39	Deferred Tax Without Proration	Line 25		($10,172,998)	($10,105,872)	($31,039)	($139,049)	$86,858	$117,401	($99,318)	($1,979)
40	Proration Adjustment	Line 38 - Line 39		$5,523,148	$5,486,704	$16,852	$75,493	($47,157)	($63,739)	$53,922	$1,074

Column Notes:
(k) Sum of remaining days in the year (Col (i)) ÷ 365
(m) through (t) = Current Year Line 25 ÷ 12 * Current Month Col (k)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of FY 2019 Net Deferred Tax Reserve Proration

Line No.	Deferred Tax Subject to Proration		(a)=Sum of (b) through (i) Total	(b) Vintage Year 2019	(c) Vintage Year 2018	(d) Vintage Year 2017	(e) Vintage Year 2016	(f) Vintage Year 2015	(g) Vintage Year 2014	(h) Vintage Year 2013	(i) Vintage Year 2012
1	Book Depreciation	Col (b) = Page 2 of 27, Line 16; Col (c) = Page 4 of 27, Line 16; Col (d) = Page 6 of 27, Line 15; Col (e) = Page 8 of 27, Line 16; Col (f) = Page 10 of 27, Line 16; Col (g) = Page 12 of 27, Line 16; Col (h) = Page 14 of 27, Line 15; Col (i) = Page 16 of 27, Line 13	$8,536,713	$1,089,239	$1,985,110	$1,810,308	$1,479,463	$2,062,926	$578,263	($464,370)	($4,227)
2	Bonus Depreciation	Page 3 of 27, Line 12	($24,048,164)	($24,048,164)	$0	$0	$0	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (b) = Page 3 of 27, Line 18; Col (c) = Page 5 of 27, Line 18; Col (d) = Page 7 of 27, Line 18; Col (e) = Page 9 of 27, Line 18; Col (f) = Page 11 of 27, Line 18; Col (g) = Page 13 of 27, Line 18; Col (h) = Page 15 of 27, Line 18; Col (i) = Page 17 of 27, Line 18	($9,024,251)	($1,527,301)	($2,193,014)	($1,967,605)	($1,598,969)	(1,678,440)	($224,640)	$167,038	($1,320)
4	FY 2019 tax (gain)/loss on retirements	Page 3 of 27, Line 19	($3,492,895)	($3,492,895)	$0	$0	$0	$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($28,023,050)	($27,979,121)	($207,904)	($157,297)	($119,506)	$384,486	$353,622	($297,333)	($5,547)
6	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($9,808,068)	($9,792,692)	($72,766)	($55,054)	($41,827)	$134,570	$123,768	($104,066)	($1,941)
	Deferred Tax Not Subject to Proration										
8	Capital Repairs Deduction	Page 3 of 27, Line 3	($26,560,800)	($26,560,800)							
9	Cost of Removal	Page 3 of 27, Line 20	($12,054,000)	($12,054,000)							
10	Book/Tax Depreciation Timing Difference at 3/31/2018		$0	$0							
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($38,614,800)	($38,614,800)							
12	Effective Tax Rate		35.00%	35.00%							
13	Deferred Tax Reserve	Line 11 * Line 12	($13,515,180)	($13,515,180)							
14	Total Deferred Tax Reserve	Line 7 + Line 13	($23,323,248)	($23,307,872)	($72,766)	($55,054)	($41,827)	$134,570	$123,768	($104,066)	($1,941)
15	Net Operating Loss	Page 2 of 27, Line 21	$0	$0							
16	Net Deferred Tax Reserve	Line 14 + Line 15	($23,323,248)	($23,307,872)	($72,766)	($55,054)	($41,827)	$134,570	$123,768	($104,066)	($1,941)
	Allocation of FY 2019 Estimated Federal NOL										
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($27,979,121)	($27,979,121)							
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($38,614,800)	($38,614,800)							
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($66,593,921)	($66,593,921)							
20	Total FY 2019 Federal NOL	(Page 2 of 27, Line 21) / 35%	$0	$0							
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0							
22	Allocated FY 2019 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0							
23	Effective Tax Rate		35.00%	35.00%							
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0							
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($9,810,009)	($9,792,692)	($72,766)	($55,054)	($41,827)	$134,570	$123,768	($104,066)	($1,941)

Line No.	**Proration Calculation**	(j) Number of Days in Month	(k) Proration Percentage	(l)= Sum of (m) through (t)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
26	April 2018	30	91.78%	($750,309)	($748,984)	($5,565)	($4,211)	($3,199)	$10,292	$9,466	($7,959)	($148)
27	May 2018	31	83.29%	($680,877)	($679,675)	($5,050)	($3,821)	($2,903)	$9,340	$8,590	($7,223)	($135)
28	June 2018	30	75.07%	($613,685)	($612,602)	($4,552)	($3,444)	($2,617)	$8,418	$7,743	($6,510)	($121)
29	July 2018	31	66.58%	($544,254)	($543,293)	($4,037)	($3,054)	($2,321)	$7,466	$6,867	($5,774)	($108)
30	August 2018	31	58.08%	($474,822)	($473,984)	($3,522)	($2,665)	($2,025)	$6,513	$5,991	($5,037)	($94)
31	September 2018	30	49.86%	($407,631)	($406,911)	($3,024)	($2,288)	($1,738)	$5,592	$5,143	($4,324)	($81)
32	October 2018	31	41.37%	($338,199)	($337,602)	($2,509)	($1,898)	($1,442)	$4,639	$4,267	($3,588)	($67)
33	November 2018	30	33.15%	($271,007)	($270,529)	($2,010)	($1,521)	($1,155)	$3,718	$3,419	($2,875)	($54)
34	December 2018	31	24.66%	($201,576)	($201,220)	($1,495)	($1,131)	($859)	$2,765	$2,543	($2,138)	($40)
35	January 2019	31	16.16%	($132,144)	($131,911)	($980)	($742)	($563)	$1,813	$1,667	($1,402)	($26)
36	February 2019	28	8.49%	($69,432)	($69,309)	($515)	($390)	($296)	$952	$876	($737)	($14)
37	March 2019	31	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	Total	365		($4,483,936)	($4,476,021)	($33,260)	($25,164)	($19,118)	$61,509	$56,572	($47,566)	($887)
39	Deferred Tax Without Proration	Line 25		($9,810,009)	($9,792,692)	($72,766)	($55,054)	($41,827)	$134,570	$123,768	($104,066)	($1,941)
40	Proration Adjustment	Line 38 - Line 39		$5,326,073	$5,316,672	$39,506	$29,890	$22,709	($73,061)	($67,196)	$56,500	$1,054

Column Notes:
(k) Sum of remaining days in the year (Col (j)) ÷ 365
(m) through (t) = Current Year Line 25 ÷ 12 * Current Month Col (k)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of FY 2020 Net Deferred Tax Reserve Proration

Line No.			(a)=Sum of (b) through (h) Total	(b) Vintage Year 2019	(c) Vintage Year 2018	(d) Vintage Year 2017	(e) Vintage Year 2016	(f) Vintage Year 2015	(g) Vintage Year 2014	(h) Vintage Year 2013	(i) Vintage Year 2012
	Deferred Tax Subject to Proration										
1	Book Depreciation	Col (b) = Page 2 of 27, Line 16; Col (c) = Page 4 of 27, Line 16; Col (d) = Page 6 of 27, Line 15; Col (e) = Page 8 of 27, Line 16; Col (f) = Page 10 of 27, Line 16; Col (g) = Page 12 of 27, Line 16; Col (h) = Page 14 of 27, Line 15; Col (i) = Page 16 of 27, Line 13	$9,625,953	$2,178,479	$1,985,110	$1,810,308	$1,479,463	$2,062,926	$578,263	($464,370)	($4,227)
2	Bonus Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Col (b) = Page 3 of 27, Line 18; Col (c) = Page 5 of 27, Line 18; Col (d) = Page 7 of 27, Line 18; Col (e) = Page 9 of 27, Line 18; Col (f) = Page 11 of 27, Line 18; Col (g) = Page 13 of 27, Line 18; Col (h) = Page 15 of 27, Line 18; Col (i) = Page 17 of 27, Line 18	($9,874,874)	($2,940,157)	($2,028,363)	($1,820,263)	($1,478,858)	$ (1,552,696)	($207,766)	$154,530	($1,302)
4	FY 2019 tax (gain)/loss on retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($248,922)	($761,678)	($43,253)	($9,955)	$605	$510,230	$370,497	($309,840)	($5,529)
6	Effective Tax Rate		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($87,123)	($266,587)	($15,138)	($3,484)	$212	$178,581	$129,674	($108,444)	($1,935)
	Deferred Tax Not Subject to Proration										
8	Capital Repairs Deduction		$0	$0							
9	Cost of Removal		$0	$0							
10	Book/Tax Depreciation Timing Difference at 3/31/2018		$0	$0							
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0							
12	Effective Tax Rate		35.00%	35.00%							
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0							
14	Total Deferred Tax Reserve	Line 7 + Line 13	($87,123)	($266,587)	($15,138)	($3,484)	$212	$178,581	$129,674	($108,444)	($1,935)
15	Net Operating Loss		$0	$0							
16	Net Deferred Tax Reserve	Line 14 + Line 15	($87,123)	($266,587)	($15,138)	($3,484)	$212	$178,581	$129,674	($108,444)	($1,935)
	Allocation of FY 2019 Estimated Federal NOL										
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($761,678)	($761,678)							
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0							
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($761,678)	($761,678)							
20	Total FY 2019 Federal NOL		$0	$0							
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0							
22	Allocated FY 2019 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0							
23	Effective Tax Rate		35.00%	35.00%							
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0							
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($87,123)	($266,587)	($15,138)	($3,484)	$212	$178,581	$129,674	($108,444)	($1,935)

Line No.	**Proration Calculation**	(j) Number of Days in Month	(k) Proration Percentage	(l)= Sum of (m) through (t)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
26	April 2018	30	91.78%	($6,663)	($20,390)	($1,158)	($266)	$16	$13,659	$9,918	($8,294)	($148)
27	May 2018	31	83.29%	($6,047)	($18,503)	($1,051)	($242)	$15	$12,395	$9,000	($7,527)	($134)
28	June 2018	30	75.07%	($5,450)	($16,677)	($947)	($218)	$13	$11,171	$8,112	($6,784)	($121)
29	July 2018	31	66.58%	($4,834)	($14,790)	($840)	($193)	$12	$9,908	$7,194	($6,016)	($107)
30	August 2018	31	58.08%	($4,217)	($12,903)	($733)	($169)	$10	$8,644	$6,276	($5,249)	($94)
31	September 2018	30	49.86%	($3,620)	($11,077)	($629)	($145)	$9	$7,420	$5,388	($4,506)	($80)
32	October 2018	31	41.37%	($3,004)	($9,191)	($522)	($120)	$7	$6,157	$4,470	($3,739)	($67)
33	November 2018	30	33.15%	($2,407)	($7,365)	($418)	($96)	$6	$4,933	$3,582	($2,996)	($53)
34	December 2018	31	24.66%	($1,790)	($5,478)	($311)	($72)	$4	$3,669	$2,665	($2,228)	($40)
35	January 2019	31	16.16%	($1,174)	($3,591)	($204)	($47)	$3	$2,406	$1,747	($1,461)	($26)
36	February 2019	28	8.49%	($617)	($1,887)	($107)	($25)	$1	$1,264	$918	($768)	($14)
37	March 2019	31	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	Total	365		($39,822)	($121,851)	($6,919)	($1,593)	$97	$81,625	$59,271	($49,567)	($885)
39	Deferred Tax Without Proration	Line 25		($87,123)	($266,587)	($15,138)	($3,484)	$212	$178,581	$129,674	($108,444)	($1,935)
40	Proration Adjustment	Line 38 - Line 39		$47,301	$144,736	$8,219	$1,892	($115)	($96,955)	($70,403)	$58,877	$1,051

Column Notes:
(k) Sum of remaining days in the year (Col (i)) ÷ 365
(m) through (t) = Current Year Line 25 ÷ 12 * Current Month Col (k)

Section 6

Rate Design and Rates
FY 2019 Electric ISR Plan Annual Filing

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors
Summary of Proposed Factors
Effective April 1, 2018 - March 31, 2018

		Residential A-16 / A-60 (a)	Small C&I C-06 (b)	General C&I G-02 (c)	200 kW Demand B-32 (d)	200 kW Demand G-32 (e)	5000 kW Demand B-62 (f)	5000 kW Demand G-62 (g)	Lighting S-05 / S-06 S-10 / S-14 (h)	Propulsion X-01 (i)
(1)	O&M Factor per kWh	$0.00193	$0.00195	$0.00142	$0.00092	$0.00092	n/a	n/a	$0.01898	$0.00142
(2)	O&M Factor per kW	n/a	n/a	n/a	n/a	n/a	n/a	$0.43	n/a	n/a
(3)	Back-Up Service O&M Factor per kW	n/a	n/a	n/a	$0.05	n/a	$0.04	n/a	n/a	n/a
(4)	CapEx kWh Factor	$0.00373	$0.00338	n/a	n/a	n/a	n/a	n/a	$0.02325	$0.00274
(5)	CapEx kW Factor	n/a	n/a	$0.84	$0.93	$0.93	$0.72	$0.72	n/a	n/a
(6)	Back-Up Service CapEx kW Factor	n/a	n/a	n/a	$0.09	n/a	$0.07	n/a	n/a	n/a

(1) Page 2, Line (6); Column (d) applicable to supplemental kWh deliveries only
(2) Page 2, Column (f), Line (8)
(3) Page 4, Line (4)
(4) Page 3, Line (6)
(5) Columns (c), through (g): Page 3, Line (8); Columns (d) and (f): applicable to supplemental service only
(6) Page 4, Line (6)

The Narragansett Electric Company
Proposed FY19 Operations & Maintenance Factors
Effective April 1, 2018 - March 31, 2018

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	5000 kW Demand B-62 / G-62 (f)	Lighting S-05 / S-06 S-10 / S-14 (g)	Propulsion X-01 (h)
(1)	FY2019 Forecasted Vegetation Management and Inspection & Maintenance O&M Expense	$11,872,251							
(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 and Inspection & Maintenance O&M Expense	$11,872,251	$5,701,279	$1,166,905	$1,834,802	$1,811,484	$435,049	$888,753	$33,978
(5)	Forecasted kWh - April 2018 through March 2019	7,292,662,088	2,952,217,339	598,406,291	1,290,644,353	1,958,411,647	422,246,350	46,812,226	23,923,882
(6)	Vegetation Management and Inspection & Maintenance O&M Expense Factor per kWh		$0.00193	$0.00195	$0.00142	$0.00092	n/a	$0.01898	$0.00142
(7)	Forecasted kW - April 2018 through March 2019						1,001,511		
(8)	Vegetation Management and Inspection & Maintenance O&M Expense Factor per kW		n/a	n/a	n/a	n/a	$0.43	n/a	n/a

(1) per Section 5: Attachment 1, Page 1, Line 5 column (b)
(2) R.I.P.U.C. 4323, Compliance Attachment 3A, (Schedule HSG-1), page 4, line 72
(3) Line (2) ÷ Line (2) Column (a)
(4) Line (1) Column (a) x Line (3)
(5) Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per estimated billing demand in forecasted kWh, and actual hours use for the period September 2016 - August 2017
(8) Line (4) ÷ Line (7), truncated to 2 decimal places

The Narragansett Electric Company
Proposed FY19 CapEx Factors
Effective April 1, 2018 - March 31, 2018

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	5000 kW Demand B-62 / G-62 (f)	Lighting S-05 / S-06 S-10 / S-14 (g)	Propulsion X-01 (h)
(1)	Proposed FY2019 Capital Investment Component of Revenue Requirement	$20,882,134							
(2)	Total Rate Base ($000s)	$561,738	$296,490	$54,542	$82,460	$77,651	$19,545	$29,286	$1,764
(3)	Percentage of Total	100.00%	52.78%	9.71%	14.68%	13.82%	3.48%	5.21%	0.31%
(4)	Allocated Proposed Revenue Requirement	$20,882,134	$11,021,746	$2,027,554	$3,065,379	$2,886,615	$726,571	$1,088,694	$65,575
(5)	Forecasted kWh - April 2018 through March 2019	7,292,662,088	2,952,217,339	598,406,291	1,290,644,353	1,958,411,647	422,246,350	46,812,226	23,923,882
(6)	Proposed CapEx Factor - per kWh		$0.00373	$0.00338	n/a	n/a	n/a	$0.02325	$0.00274
(7)	Forecasted kW - April 2018 through March 2019				3,618,449	3,097,294	1,001,511		
(8)	Proposed CapEx Factor - per kW		n/a	n/a	$0.84	$0.93	$0.72	n/a	n/a

(1) Section 5: Attachment 1, Page 1, Line 20, Column (b)
(2) R.I.P.U.C. 4323, Compliance Attachment 3A, (Schedule HSG-1), Page 2, Line (10)
(3) Line (2) ÷ Line (2) Column (a)
(4) Line (1), Column (a) x Line (3)
(5) per Company forecast
(6) Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per estimated billing demand in forecasted kWh, and actual hours use for the period September 2016 - August 2017
(8) 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 B-32/G-32

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

		200 kW Demand B-32 (a)	5000 kW Demand B-62 (b)
	Operations & Maintenance Factors		
(1)	Allocated Vegetation Management and Inspection & Maintenance O&M Expense	$1,811,484	$435,049
(2)	Forecasted kW - April 2018 through March 2019	3,097,294	1,001,511
(3)	Vegetation Management and Inspection & Maintenance O&M Expense Charge per kW	$0.58	$0.43
(4)	Discounted O&M kW Factor effective April 1, 2018	$0.05	$0.04
	CapEx Factors		
(5)	Proposed CapEx kW Factor effective April 1, 2018	$0.93	$0.72
(6)	Discounted CapEx kW Factor effective April 1, 2018	$0.09	$0.07

(1) Page 2, Line (4)
(2) per estimated billing demand in forecasted kWh, and actual hours use for the period September 2016 - August 2017
(3) Line (1) ÷ Line (2), truncated to 2 decimal places
(4) Line (3) x .10, truncated to 2 decimal places
(5) Page 3, Line (8)
(6) Line (5) x .10, truncated to 2 decimal places

Section 7
Bill Impacts

Section 7

Bill Impacts
FY 2019 Electric ISR Plan Annual Filing

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

Monthly kWh	Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	
150	$20.66	$14.27	$1.46	$36.39	$20.83	$14.27	$1.46	$36.56	$0.17	$0.00	$0.00	$0.17	0.5%	0.0%	0.0%	0.5%	13.7%
300	$34.72	$28.55	$2.64	$65.91	$35.07	$28.55	$2.65	$66.27	$0.35	$0.00	$0.01	$0.36	0.5%	0.0%	0.0%	0.5%	17.5%
400	$44.10	$38.06	$3.42	$85.58	$44.56	$38.06	$3.44	$86.06	$0.46	$0.00	$0.02	$0.48	0.5%	0.0%	0.0%	0.6%	11.8%
500	$53.48	$47.58	$4.21	$105.27	$54.05	$47.58	$4.23	$105.86	$0.57	$0.00	$0.02	$0.59	0.5%	0.0%	0.0%	0.6%	10.8%
600	$62.85	$57.09	$5.00	$124.94	$63.54	$57.09	$5.03	$125.66	$0.69	$0.00	$0.03	$0.72	0.6%	0.0%	0.0%	0.6%	9.4%
700	$72.23	$66.61	$5.79	$144.63	$73.03	$66.61	$5.82	$145.46	$0.80	$0.00	$0.03	$0.83	0.6%	0.0%	0.0%	0.6%	7.7%
1,200	$119.11	$114.18	$9.72	$243.01	$120.49	$114.18	$9.78	$244.45	$1.38	$0.00	$0.06	$1.44	0.6%	0.0%	0.0%	0.6%	15.0%
2,000	$194.13	$190.30	$16.02	$400.45	$196.43	$190.30	$16.11	$402.84	$2.30	$0.00	$0.09	$2.39	0.6%	0.0%	0.0%	0.6%	14.1%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$5.00		$5.00	
RE Growth Factor		$0.78		$0.78	
LIHEAP Charge		$0.81		$0.81	
Transmission Energy Charge	kWh x	$0.03179		$0.03179	
Distribution Energy Charge	kWh x	$0.04300	(1)	$0.04415	(2)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09515		$0.09515	

Note (1): includes CapEx Factor of 0.288¢/kWh and O&M Factor of 0.163¢/kWh
Note (2): includes the proposed CapEx Factor of 0.373¢/kWh and the proposed O&M Factor of 0.193¢/kWh

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

	Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)								
									$				% of Total Bill				
Monthly kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Percentage of Customers
150	$13.64	$14.27	$1.16	$29.07	$13.81	$14.27	$1.17	$29.25	$0.17	$0.00	$0.01	$0.18	0.6%	0.0%	0.0%	0.6%	13.7%
300	$25.68	$28.55	$2.26	$56.49	$26.03	$28.55	$2.27	$56.85	$0.35	$0.00	$0.01	$0.36	0.6%	0.0%	0.0%	0.6%	17.5%
400	$33.71	$38.06	$2.99	$74.76	$34.17	$38.06	$3.01	$75.24	$0.46	$0.00	$0.02	$0.48	0.6%	0.0%	0.0%	0.6%	11.8%
500	$41.74	$47.58	$3.72	$93.04	$42.32	$47.58	$3.75	$93.65	$0.58	$0.00	$0.03	$0.61	0.6%	0.0%	0.0%	0.7%	10.8%
600	$49.77	$57.09	$4.45	$111.31	$50.46	$57.09	$4.48	$112.03	$0.69	$0.00	$0.03	$0.72	0.6%	0.0%	0.0%	0.6%	9.4%
700	$57.80	$66.61	$5.18	$129.59	$58.61	$66.61	$5.22	$130.44	$0.81	$0.00	$0.04	$0.85	0.6%	0.0%	0.0%	0.7%	7.7%
1,200	$97.95	$114.18	$8.84	$220.97	$99.33	$114.18	$8.90	$222.41	$1.38	$0.00	$0.06	$1.44	0.6%	0.0%	0.0%	0.7%	15.0%
2,000	$162.19	$190.30	$14.69	$367.18	$164.49	$190.30	$14.78	$369.57	$2.30	$0.00	$0.09	$2.39	0.6%	0.0%	0.0%	0.7%	14.1%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$0.00		$0.00	
RE Growth Factor		$0.78		$0.78	
LIHEAP Charge		$0.81		$0.81	
Transmission Energy Charge	kWh x	$0.03179		$0.03179	
Distribution Energy Charge	kWh x	$0.02953	(1)	$0.03068	(2)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09515		$0.09515	

Note (1): includes CapEx Factor of 0.288¢/kWh and O&M Factor of 0.163¢/kWh
Note (2): includes the proposed CapEx Factor of 0.373¢/kWh and the proposed O&M Factor of 0.193¢/kWh

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

Monthly	Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)								Percentage
									$				% of Total Bill				
kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	of Customers
250	$33.64	$23.38	$2.38	$59.40	$33.88	$23.38	$2.39	$59.65	$0.24	$0.00	$0.01	$0.25	0.4%	0.0%	0.0%	0.4%	35.2%
500	$55.21	$46.75	$4.25	$106.21	$55.69	$46.75	$4.27	$106.71	$0.48	$0.00	$0.02	$0.50	0.5%	0.0%	0.0%	0.5%	17.0%
1,000	$98.35	$93.50	$7.99	$199.84	$99.30	$93.50	$8.03	$200.83	$0.95	$0.00	$0.04	$0.99	0.5%	0.0%	0.0%	0.5%	19.0%
1,500	$141.49	$140.25	$11.74	$293.48	$142.92	$140.25	$11.80	$294.97	$1.43	$0.00	$0.06	$1.49	0.5%	0.0%	0.0%	0.5%	9.8%
2,000	$184.63	$187.00	$15.48	$387.11	$186.53	$187.00	$15.56	$389.09	$1.90	$0.00	$0.08	$1.98	0.5%	0.0%	0.0%	0.5%	19.1%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$10.00		$10.00	
RE Growth Factor		$1.26		$1.26	
LIHEAP Charge		$0.81		$0.81	
Transmission Energy Charge	kWh x	$0.02838		$0.02838	
Distribution Energy Charge	kWh x	$0.03892	(1)	$0.03987	(2)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09350		$0.09350	

Note (1): includes CapEx Factor of 0.269¢/kWh and O&M Factor of 0.169¢/kWh
Note (2): includes the proposed CapEx Factor of 0.338¢/kWh and the proposed O&M Factor of 0.195¢/kWh

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

Hours Use: 200

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	4000	$442.50	$374.00	$34.02	$850.52	$445.00	$374.00	$34.13	$853.13	$2.50	$0.00	$0.11	$2.61	0.3%	0.0%	0.0%	0.3%
50	10000	$967.56	$935.00	$79.27	$1,981.83	$976.36	$935.00	$79.64	$1,991.00	$8.80	$0.00	$0.37	$9.17	0.4%	0.0%	0.0%	0.5%
100	20000	$1,842.66	$1,870.00	$154.69	$3,867.35	$1,861.96	$1,870.00	$155.50	$3,887.46	$19.30	$0.00	$0.81	$20.11	0.5%	0.0%	0.0%	0.5%
150	30000	$2,717.76	$2,805.00	$230.12	$5,752.88	$2,747.56	$2,805.00	$231.36	$5,783.92	$29.80	$0.00	$1.24	$31.04	0.5%	0.0%	0.0%	0.5%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$11.85		$11.85	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.37		$4.37	
Transmission Energy Charge	kWh x	$0.01096		$0.01096	
Distribution Demand Charge-xcs 10 kW	kW x	$5.52	(1)	$5.69	(2)
Distribution Energy Charge	kWh x	$0.00812	(3)	$0.00832	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09350		$0.09350	

Note (1): includes CapEx Factor of 67¢/kW
Note (2): includes the proposed CapEx Factor of 84¢/kW
Note (3): includes O&M Factor of 0.122¢/kWh
Note (4): includes the proposed O&M Factor of 0.142¢/kWh

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

Hours Use: 300

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	6000	$518.62	$561.00	$44.98	$1,124.60	$521.52	$561.00	$45.11	$1,127.63	$2.90	$0.00	$0.13	$3.03	0.3%	0.0%	0.0%	0.3%
50	15000	$1,157.86	$1,402.50	$106.68	$2,667.04	$1,167.66	$1,402.50	$107.09	$2,677.25	$9.80	$0.00	$0.41	$10.21	0.4%	0.0%	0.0%	0.4%
100	30000	$2,223.26	$2,805.00	$209.51	$5,237.77	$2,244.56	$2,805.00	$210.40	$5,259.96	$21.30	$0.00	$0.89	$22.19	0.4%	0.0%	0.0%	0.4%
150	45000	$3,288.66	$4,207.50	$312.34	$7,808.50	$3,321.46	$4,207.50	$313.71	$7,842.67	$32.80	$0.00	$1.37	$34.17	0.4%	0.0%	0.0%	0.4%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$11.85		$11.85	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.37		$4.37	
Transmission Energy Charge	kWh x	$0.01096		$0.01096	
Distribution Demand Charge-xcs 10 kW	kW x	$5.52	(1)	$5.69	(2)
Distribution Energy Charge	kWh x	$0.00812	(3)	$0.00832	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09350		$0.09350	

Note (1): includes CapEx Factor of 67¢/kW
Note (2): includes the proposed CapEx Factor of 84¢/kW
Note (3): includes O&M Factor of 0.122¢/kWh
Note (4): includes the proposed O&M Factor of 0.142¢/kWh

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

Hours Use: 400

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	8000	$594.74	$748.00	$55.95	$1,398.69	$598.04	$748.00	$56.09	$1,402.13	$3.30	$0.00	$0.14	$3.44	0.2%	0.0%	0.0%	0.2%
50	20000	$1,348.16	$1,870.00	$134.09	$3,352.25	$1,358.96	$1,870.00	$134.54	$3,363.50	$10.80	$0.00	$0.45	$11.25	0.3%	0.0%	0.0%	0.3%
100	40000	$2,603.86	$3,740.00	$264.33	$6,608.19	$2,627.16	$3,740.00	$265.30	$6,632.46	$23.30	$0.00	$0.97	$24.27	0.4%	0.0%	0.0%	0.4%
150	60000	$3,859.56	$5,610.00	$394.57	$9,864.13	$3,895.36	$5,610.00	$396.06	$9,901.42	$35.80	$0.00	$1.49	$37.29	0.4%	0.0%	0.0%	0.4%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$11.85		$11.85	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.37		$4.37	
Transmission Energy Charge	kWh x	$0.01096		$0.01096	
Distribution Demand Charge-xcs 10 kW	kW x	$5.52	(1)	$5.69	(2)
Distribution Energy Charge	kWh x	$0.00812	(3)	$0.00832	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09350		$0.09350	

Note (1): includes CapEx Factor of 67¢/kW
Note (2): includes the proposed CapEx Factor of 84¢/kW
Note (3): includes O&M Factor of 0.122¢/kWh
Note (4): includes the proposed O&M Factor of 0.142¢/kWh

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

Hours Use: 500

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	10000	$670.86	$935.00	$66.91	$1,672.77	$674.56	$935.00	$67.07	$1,676.63	$3.70	$0.00	$0.16	$3.86	0.2%	0.0%	0.0%	0.2%
50	25000	$1,538.46	$2,337.50	$161.50	$4,037.46	$1,550.26	$2,337.50	$161.99	$4,049.75	$11.80	$0.00	$0.49	$12.29	0.3%	0.0%	0.0%	0.3%
100	50000	$2,984.46	$4,675.00	$319.14	$7,978.60	$3,009.76	$4,675.00	$320.20	$8,004.96	$25.30	$0.00	$1.06	$26.36	0.3%	0.0%	0.0%	0.3%
150	75000	$4,430.46	$7,012.50	$476.79	$11,919.75	$4,469.26	$7,012.50	$478.41	$11,960.17	$38.80	$0.00	$1.62	$40.42	0.3%	0.0%	0.0%	0.3%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$11.85		$11.85	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.37		$4.37	
Transmission Energy Charge	kWh x	$0.01096		$0.01096	
Distribution Demand Charge-xcs 10 kW	kW x	$5.52	(1)	$5.69	(2)
Distribution Energy Charge	kWh x	$0.00812	(3)	$0.00832	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09350		$0.09350	

Note (1): includes CapEx Factor of 67¢/kW
Note (2): includes the proposed CapEx Factor of 84¢/kW
Note (3): includes O&M Factor of 0.122¢/kWh
Note (4): includes the proposed O&M Factor of 0.142¢/kWh

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

Hours Use: 600

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
20	12000	$746.98	$1,122.00	$77.87	$1,946.85	$751.08	$1,122.00	$78.05	$1,951.13	$4.10	$0.00	$0.18	$4.28	0.2%	0.0%	0.0%	0.2%
50	30000	$1,728.76	$2,805.00	$188.91	$4,722.67	$1,741.56	$2,805.00	$189.44	$4,736.00	$12.80	$0.00	$0.53	$13.33	0.3%	0.0%	0.0%	0.3%
100	60000	$3,365.06	$5,610.00	$373.96	$9,349.02	$3,392.36	$5,610.00	$375.10	$9,377.46	$27.30	$0.00	$1.14	$28.44	0.3%	0.0%	0.0%	0.3%
150	90000	$5,001.36	$8,415.00	$559.02	$13,975.38	$5,043.16	$8,415.00	$560.76	$14,018.92	$41.80	$0.00	$1.74	$43.54	0.3%	0.0%	0.0%	0.3%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$135.00		$135.00	
RE Growth Factor		$11.85		$11.85	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.37		$4.37	
Transmission Energy Charge	kWh x	$0.01096		$0.01096	
Distribution Demand Charge-xcs 10 kW	kW x	$5.52	(1)	$5.69	(2)
Distribution Energy Charge	kWh x	$0.00812	(3)	$0.00832	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.09350		$0.09350	

Note (1): includes CapEx Factor of 67¢/kW
Note (2): includes the proposed CapEx Factor of 84¢/kW
Note (3): includes O&M Factor of 0.122¢/kWh
Note (4): includes the proposed O&M Factor of 0.142¢/kWh

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

Hours Use: 200

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	40,000	$3,419.07	$2,576.00	$249.79	$6,244.86	$3,424.27	$2,576.00	$250.01	$6,250.28	$5.20	$0.00	$0.22	$5.42	0.1%	0.0%	0.0%	0.1%
750	150,000	$12,737.17	$9,660.00	$933.22	$23,330.39	$12,877.67	$9,660.00	$939.07	$23,476.74	$140.50	$0.00	$5.85	$146.35	0.6%	0.0%	0.0%	0.6%
1,000	200,000	$16,972.67	$12,880.00	$1,243.86	$31,096.53	$17,174.67	$12,880.00	$1,252.28	$31,306.95	$202.00	$0.00	$8.42	$210.42	0.6%	0.0%	0.0%	0.7%
1,500	300,000	$25,443.67	$19,320.00	$1,865.15	$46,628.82	$25,768.67	$19,320.00	$1,878.69	$46,967.36	$325.00	$0.00	$13.54	$338.54	0.7%	0.0%	0.0%	0.7%
2,500	500,000	$42,385.67	$32,200.00	$3,107.74	$77,693.41	$42,956.67	$32,200.00	$3,131.53	$78,288.20	$571.00	$0.00	$23.79	$594.79	0.7%	0.0%	0.0%	0.8%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$86.86		$86.86	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.69		$4.69	
Transmission Energy Charge	kWh x	$0.01123		$0.01123	
Distribution Demand Charge-xcs 10 kW	kW x	$4.41	(1)	$4.63	(2)
Distribution Energy Charge	kWh x	$0.00900	(3)	$0.00913	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(5)	$0.06440	(5)

Note (1): includes CapEx Factor of 71¢/kW
Note (2): includes the proposed CapEx Factor of 93¢/kW
Note (3): includes O&M Factor of 0.079¢/kWh
Note (4): includes the proposed O&M Factor of 0.092¢/kWh
Note (5): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 300

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	60,000	$4,203.27	$3,864.00	$336.14	$8,403.41	$4,211.07	$3,864.00	$336.46	$8,411.53	$7.80	$0.00	$0.32	$8.12	0.1%	0.0%	0.0%	0.1%
750	225,000	$15,677.92	$14,490.00	$1,257.00	$31,424.92	$15,828.17	$14,490.00	$1,263.26	$31,581.43	$150.25	$0.00	$6.26	$156.51	0.5%	0.0%	0.0%	0.5%
1,000	300,000	$20,893.67	$19,320.00	$1,675.57	$41,889.24	$21,108.67	$19,320.00	$1,684.53	$42,113.20	$215.00	$0.00	$8.96	$223.96	0.5%	0.0%	0.0%	0.5%
1,500	450,000	$31,325.17	$28,980.00	$2,512.72	$62,817.89	$31,669.67	$28,980.00	$2,527.07	$63,176.74	$344.50	$0.00	$14.35	$358.85	0.5%	0.0%	0.0%	0.6%
2,500	750,000	$52,188.17	$48,300.00	$4,187.01	$104,675.18	$52,791.67	$48,300.00	$4,212.15	$105,303.82	$603.50	$0.00	$25.14	$628.64	0.6%	0.0%	0.0%	0.6%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$86.86		$86.86	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.69		$4.69	
Transmission Energy Charge	kWh x	$0.01123		$0.01123	
Distribution Demand Charge-xcs 10 kW	kW x	$4.41	(1)	$4.63	(2)
Distribution Energy Charge	kWh x	$0.00900	(2)	$0.00913	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(5)	$0.06440	(5)

Note (1): includes CapEx Factor of 71¢/kW
Note (2): includes the proposed CapEx Factor of 93¢/kW
Note (3): includes O&M Factor of 0.079¢/kWh
Note (4): includes the proposed O&M Factor of 0.092¢/kWh
Note (5): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 400

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	80,000	$4,987.47	$5,152.00	$422.48	$10,561.95	$4,997.87	$5,152.00	$422.91	$10,572.78	$10.40	$0.00	$0.43	$10.83	0.1%	0.0%	0.0%	0.1%
750	300,000	$18,618.67	$19,320.00	$1,580.78	$39,519.45	$18,778.67	$19,320.00	$1,587.44	$39,686.11	$160.00	$0.00	$6.66	$166.66	0.4%	0.0%	0.0%	0.4%
1,000	400,000	$24,814.67	$25,760.00	$2,107.28	$52,681.95	$25,042.67	$25,760.00	$2,116.78	$52,919.45	$228.00	$0.00	$9.50	$237.50	0.4%	0.0%	0.0%	0.5%
1,500	600,000	$37,206.67	$38,640.00	$3,160.28	$79,006.95	$37,570.67	$38,640.00	$3,175.44	$79,386.11	$364.00	$0.00	$15.16	$379.16	0.5%	0.0%	0.0%	0.5%
2,500	1,000,000	$61,990.67	$64,400.00	$5,266.28	$131,656.95	$62,626.67	$64,400.00	$5,292.78	$132,319.45	$636.00	$0.00	$26.50	$662.50	0.5%	0.0%	0.0%	0.5%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$86.86		$86.86	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.69		$4.69	
Transmission Energy Charge	kWh x	$0.01123		$0.01123	
Distribution Demand Charge-xcs 10 kW	kW x	$4.41	(1)	$4.63	(2)
Distribution Energy Charge	kWh x	$0.00900	(3)	$0.00913	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(5)	$0.06440	(5)

Note (1): includes CapEx Factor of 71¢/kW
Note (2): includes the proposed CapEx Factor of 93¢/kW
Note (3): includes O&M Factor of 0.079¢/kWh
Note (4): includes the proposed O&M Factor of 0.092¢/kWh
Note (5): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 500

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	100,000	$5,771.67	$6,440.00	$508.82	$12,720.49	$5,784.67	$6,440.00	$509.36	$12,734.03	$13.00	$0.00	$0.54	$13.54	0.1%	0.0%	0.0%	0.1%
750	375,000	$21,559.42	$24,150.00	$1,904.56	$47,613.98	$21,729.17	$24,150.00	$1,911.63	$47,790.80	$169.75	$0.00	$7.07	$176.82	0.4%	0.0%	0.0%	0.4%
1,000	500,000	$28,735.67	$32,200.00	$2,538.99	$63,474.66	$28,976.67	$32,200.00	$2,549.03	$63,725.70	$241.00	$0.00	$10.04	$251.04	0.4%	0.0%	0.0%	0.4%
1,500	750,000	$43,088.17	$48,300.00	$3,807.84	$95,196.01	$43,471.67	$48,300.00	$3,823.82	$95,595.49	$383.50	$0.00	$15.98	$399.48	0.4%	0.0%	0.0%	0.4%
2,500	1,250,000	$71,793.17	$80,500.00	$6,345.55	$158,638.72	$72,461.67	$80,500.00	$6,373.40	$159,335.07	$668.50	$0.00	$27.85	$696.35	0.4%	0.0%	0.0%	0.4%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$86.86		$86.86	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.69		$4.69	
Transmission Energy Charge	kWh x	$0.01123		$0.01123	
Distribution Demand Charge-xcs 10 kW	kW x	$4.41	(1)	$4.63	(2)
Distribution Energy Charge	kWh x	$0.00900	(3)	$0.00913	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(5)	$0.06440	(5)

Note (1): includes CapEx Factor of 71¢/kW
Note (2): includes the proposed CapEx Factor of 93¢/kW
Note (3): includes O&M Factor of 0.079¢/kWh
Note (4): includes the proposed O&M Factor of 0.092¢/kWh
Note (5): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 600

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease) $				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
200	120,000	$6,555.87	$7,728.00	$595.16	$14,879.03	$6,571.47	$7,728.00	$595.81	$14,895.28	$15.60	$0.00	$0.65	$16.25	0.1%	0.0%	0.0%	0.1%
750	450,000	$24,500.17	$28,980.00	$2,228.34	$55,708.51	$24,679.67	$28,980.00	$2,235.82	$55,895.49	$179.50	$0.00	$7.48	$186.98	0.3%	0.0%	0.0%	0.3%
1,000	600,000	$32,656.67	$38,640.00	$2,970.69	$74,267.36	$32,910.67	$38,640.00	$2,981.28	$74,531.95	$254.00	$0.00	$10.59	$264.59	0.3%	0.0%	0.0%	0.4%
1,500	900,000	$48,969.67	$57,960.00	$4,455.40	$111,385.07	$49,372.67	$57,960.00	$4,472.19	$111,804.86	$403.00	$0.00	$16.79	$419.79	0.4%	0.0%	0.0%	0.4%
2,500	1,500,000	$81,595.67	$96,600.00	$7,424.82	$185,620.49	$82,296.67	$96,600.00	$7,454.03	$186,350.70	$701.00	$0.00	$29.21	$730.21	0.4%	0.0%	0.0%	0.4%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$825.00		$825.00	
RE Growth Factor		$86.86		$86.86	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$4.69		$4.69	
Transmission Energy Charge	kWh x	$0.01123		$0.01123	
Distribution Demand Charge-xcs 10 kW	kW x	$4.41	(1)	$4.63	(2)
Distribution Energy Charge	kWh x	$0.00900	(3)	$0.00913	(4)
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(5)	$0.06440	(5)

Note (1): includes CapEx Factor of 71¢/kW
Note (2): includes the proposed CapEx Factor of 93¢/kW
Note (3): includes O&M Factor of 0.079¢/kWh
Note (4): includes the proposed O&M Factor of 0.092¢/kWh
Note (5): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 200

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease) $				Increase (Decrease) % of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	600,000	$63,052.89	$38,640.00	$4,237.20	$105,930.09	$63,772.89	$38,640.00	$4,267.20	$106,680.09	$720.00	$0.00	$30.00	$750.00	0.7%	0.0%	0.0%	0.7%
5,000	1,000,000	$92,468.89	$64,400.00	$6,536.20	$163,405.09	$93,668.89	$64,400.00	$6,586.20	$164,655.09	$1,200.00	$0.00	$50.00	$1,250.00	0.7%	0.0%	0.0%	0.8%
7,500	1,500,000	$129,238.89	$96,600.00	$9,409.95	$235,248.84	$131,038.89	$96,600.00	$9,484.95	$237,123.84	$1,800.00	$0.00	$75.00	$1,875.00	0.8%	0.0%	0.0%	0.8%
10,000	2,000,000	$166,008.89	$128,800.00	$12,283.70	$307,092.59	$168,408.89	$128,800.00	$12,383.70	$309,592.59	$2,400.00	$0.00	$100.00	$2,500.00	0.8%	0.0%	0.0%	0.8%
20,000	4,000,000	$313,088.89	$257,600.00	$23,778.70	$594,467.59	$317,888.89	$257,600.00	$23,978.70	$599,467.59	$4,800.00	$0.00	$200.00	$5,000.00	0.8%	0.0%	0.0%	0.8%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$1,928.08		$1,928.08	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$3.40		$3.40	
Transmission Energy Charge	kWh x	$0.01524		$0.01524	
Distribution Demand Charge-xcs 10 kW	kW x	$3.90	(1)	$4.14	(2)
Distribution Energy Charge	kWh x	$0.00282		$0.00282	
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(3)	$0.06440	(3)

Note (1): includes CapEx Factor of 55¢/kW and O&M Factor of 36¢/kW
Note (2): includes the proposed CapEx Factor of 72¢/kW and the proposed O&M Factor of 43¢/kW

Note (3): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 300

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	900,000	$74,164.89	$57,960.00	$5,505.20	$137,630.09	$74,884.89	$57,960.00	$5,535.20	$138,380.09	$720.00	$0.00	$30.00	$750.00	0.5%	0.0%	0.0%	0.5%
5,000	1,500,000	$110,988.89	$96,600.00	$8,649.54	$216,238.43	$112,188.89	$96,600.00	$8,699.54	$217,488.43	$1,200.00	$0.00	$50.00	$1,250.00	0.6%	0.0%	0.0%	0.6%
7,500	2,250,000	$157,018.89	$144,900.00	$12,579.95	$314,498.84	$158,818.89	$144,900.00	$12,654.95	$316,373.84	$1,800.00	$0.00	$75.00	$1,875.00	0.6%	0.0%	0.0%	0.6%
10,000	3,000,000	$203,048.89	$193,200.00	$16,510.37	$412,759.26	$205,448.89	$193,200.00	$16,610.37	$415,259.26	$2,400.00	$0.00	$100.00	$2,500.00	0.6%	0.0%	0.0%	0.6%
20,000	6,000,000	$387,168.89	$386,400.00	$32,232.04	$805,800.93	$391,968.89	$386,400.00	$32,432.04	$810,800.93	$4,800.00	$0.00	$200.00	$5,000.00	0.6%	0.0%	0.0%	0.6%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$1,928.08		$1,928.08	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$3.40		$3.40	
Transmission Energy Charge	kWh x	$0.01524		$0.01524	
Distribution Demand Charge-xcs 10 kW	kW x	$3.90	(1)	$4.14	(2)
Distribution Energy Charge	kWh x	$0.00282		$0.00282	
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(3)	$0.06440	(3)

Note (1): includes CapEx Factor of 55¢/kW and O&M Factor of 36¢/kW
Note (2): includes the proposed CapEx Factor of 72¢/kW and the proposed O&M Factor of 43¢/kW
Note (3): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 400

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	1,200,000	$85,276.89	$77,280.00	$6,773.20	$169,330.09	$85,996.89	$77,280.00	$6,803.20	$170,080.09	$720.00	$0.00	$30.00	$750.00	0.4%	0.0%	0.0%	0.4%
5,000	2,000,000	$129,508.89	$128,800.00	$10,762.87	$269,071.76	$130,708.89	$128,800.00	$10,812.87	$270,321.76	$1,200.00	$0.00	$50.00	$1,250.00	0.4%	0.0%	0.0%	0.5%
7,500	3,000,000	$184,798.89	$193,200.00	$15,749.95	$393,748.84	$186,598.89	$193,200.00	$15,824.95	$395,623.84	$1,800.00	$0.00	$75.00	$1,875.00	0.5%	0.0%	0.0%	0.5%
10,000	4,000,000	$240,088.89	$257,600.00	$20,737.04	$518,425.93	$242,488.89	$257,600.00	$20,837.04	$520,925.93	$2,400.00	$0.00	$100.00	$2,500.00	0.5%	0.0%	0.0%	0.5%
20,000	8,000,000	$461,248.89	$515,200.00	$40,685.37	$1,017,134.26	$466,048.89	$515,200.00	$40,885.37	$1,022,134.26	$4,800.00	$0.00	$200.00	$5,000.00	0.5%	0.0%	0.0%	0.5%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$1,928.08		$1,928.08	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$3.40		$3.40	
Transmission Energy Charge	kWh x	$0.01524		$0.01524	
Distribution Demand Charge-xcs 10 kW	kW x	$3.90	(1)	$4.14	(2)
Distribution Energy Charge	kWh x	$0.00282		$0.00282	
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(3)	$0.06440	(3)

Note (1): includes CapEx Factor of 55¢/kW and O&M Factor of 36¢/kW
Note (2): includes the proposed CapEx Factor of 72¢/kW and the proposed O&M Factor of 43¢/kW
Note (3): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 500

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	1,500,000	$96,388.89	$96,600.00	$8,041.20	$201,030.09	$97,108.89	$96,600.00	$8,071.20	$201,780.09	$720.00	$0.00	$30.00	$750.00	0.4%	0.0%	0.0%	0.4%
5,000	2,500,000	$148,028.89	$161,000.00	$12,876.20	$321,905.09	$149,228.89	$161,000.00	$12,926.20	$323,155.09	$1,200.00	$0.00	$50.00	$1,250.00	0.4%	0.0%	0.0%	0.4%
7,500	3,750,000	$212,578.89	$241,500.00	$18,919.95	$472,998.84	$214,378.89	$241,500.00	$18,994.95	$474,873.84	$1,800.00	$0.00	$75.00	$1,875.00	0.4%	0.0%	0.0%	0.4%
10,000	5,000,000	$277,128.89	$322,000.00	$24,963.70	$624,092.59	$279,528.89	$322,000.00	$25,063.70	$626,592.59	$2,400.00	$0.00	$100.00	$2,500.00	0.4%	0.0%	0.0%	0.4%
20,000	10,000,000	$535,328.89	$644,000.00	$49,138.70	$1,228,467.59	$540,128.89	$644,000.00	$49,338.70	$1,233,467.59	$4,800.00	$0.00	$200.00	$5,000.00	0.4%	0.0%	0.0%	0.4%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$1,928.08		$1,928.08	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$3.40		$3.40	
Transmission Energy Charge	kWh x	$0.01524		$0.01524	
Distribution Demand Charge-xcs 10 kW	kW x	$3.90	(1)	$4.14	(2)
Distribution Energy Charge	kWh x	$0.00282		$0.00282	
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(3)	$0.06440	(3)

Note (1): includes CapEx Factor of 55¢/kW and O&M Factor of 36¢/kW
Note (2): includes the proposed CapEx Factor of 72¢/kW and the proposed O&M Factor of 43¢/kW
Note (3): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

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

Hours Use: 600

Monthly Power		Current Rates as of 12/1/2017				Proposed Rates				Increase (Decrease)							
										$				% of Total Bill			
kW	kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total
3,000	1,800,000	$107,500.89	$115,920.00	$9,309.20	$232,730.09	$108,220.89	$115,920.00	$9,339.20	$233,480.09	$720.00	$0.00	$30.00	$750.00	0.3%	0.0%	0.0%	0.3%
5,000	3,000,000	$166,548.89	$193,200.00	$14,989.54	$374,738.43	$167,748.89	$193,200.00	$15,039.54	$375,988.43	$1,200.00	$0.00	$50.00	$1,250.00	0.3%	0.0%	0.0%	0.3%
7,500	4,500,000	$240,358.89	$289,800.00	$22,089.95	$552,248.84	$242,158.89	$289,800.00	$22,164.95	$554,123.84	$1,800.00	$0.00	$75.00	$1,875.00	0.3%	0.0%	0.0%	0.3%
10,000	6,000,000	$314,168.89	$386,400.00	$29,190.37	$729,759.26	$316,568.89	$386,400.00	$29,290.37	$732,259.26	$2,400.00	$0.00	$100.00	$2,500.00	0.3%	0.0%	0.0%	0.3%
20,000	12,000,000	$609,408.89	$772,800.00	$57,592.04	$1,439,800.93	$614,208.89	$772,800.00	$57,792.04	$1,444,800.93	$4,800.00	$0.00	$200.00	$5,000.00	0.3%	0.0%	0.0%	0.3%

		Current Rates as of 12/1/2017		Proposed Rates	
Customer Charge		$17,000.00		$17,000.00	
RE Growth Factor		$1,928.08		$1,928.08	
LIHEAP Charge		$0.81		$0.81	
Transmission Demand Charge	kW x	$3.40		$3.40	
Transmission Energy Charge	kWh x	$0.01524		$0.01524	
Distribution Demand Charge-xcs 10 kW	kW x	$3.90	(1)	$4.14	(2)
Distribution Energy Charge	kWh x	$0.00282		$0.00282	
Transition Energy Charge	kWh x	$0.00057		$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154		$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00687		$0.00687	
Gross Earnings Tax		4%		4%	
Standard Offer Charge	kWh x	$0.06440	(3)	$0.06440	(3)

Note (1): includes CapEx Factor of 55¢/kW and O&M Factor of 36¢/kW
Note (2): includes the proposed CapEx Factor of 72¢/kW and the proposed O&M Factor of 43¢/kW
Note (3): includes the base average October-December 2017 Standard Offer Service Charge of 6.785¢/kWh, the Standard Offer Service Adjustment Charge of (0.507¢)/kWh, the Standard Offer Service Administrative Cost Factor of 0.122¢/kWh and the Renewable Energy Standard Charge of 0.040¢/kWh

Testimony of
William R. Richer

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM R. RICHER

December 21, 2017

Table of Contents

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 at National Grid and responsibilities in that position.

A. I am the Director of Revenue Requirements for National Grid USA Service Company, Inc. (Service Company), where I provide services to The Narragansett Electric Company d/b/a National Grid (Company) for both its gas and electric businesses.

Q. Please describe your education and professional experience.

A. In 1985, I earned a Bachelor of Science degree in Accounting from Northeastern University. During college, 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 became a Certified Public Accountant in the State of Rhode Island. In June 1990, I joined National Grid (then known as New England Electric System) 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 (PUC)?

A. Yes, I have testified before the PUC on numerous occasions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 5 of the FY 2019 Electric ISR Plan, which describes the calculation of the Company's revenue requirement for FY 2019 in Attachment 1 of that section. The revenue requirement is based on the FY 2019 Electric ISR Plan operation and maintenance (O&M) expenses and capital investment, which are described in the joint testimony of Mr. Prabhjot S. Anand and Mr. Ryan Moe.

III. ISR PLAN REVENUE REQUIREMENT

Q. Please summarize the revenue requirement for the Company's FY 2019 Electric ISR Plan.

A. As shown on Page 1, Column (b) of Attachment 1, the Company's FY 2019 Electric ISR Plan revenue requirement totals $32,754,385and includes the following elements: (1) operation and maintenance (O&M) expense associated with the Company's vegetation management (VM) activities, the Company's Inspection and Maintenance (I&M) Program and other costs related to maintaining the safety and reliability of the electric distribution system., all totaling $11,872,251; (2) the FY 2019 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $17,786,961, which includes the $3,087,133 revenue requirement on FY 2019 proposed incremental ISR capital investment, plus the FY 2019 revenue requirements on incremental ISR capital investment for FY 2012 through FY 2018, totaling $14,699,828; and (3) FY 2019 Property Tax Recovery Adjustment of $3,095,173. Importantly, these amounts will be trued up to actual O&M and capital investment activity after the conclusion of the fiscal year, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

For illustration purposes only, Column (c), Page 1 of Attachment 1 provides the FY 2020 revenue requirement. Please see Section 5 of the FY 2019 Electric ISR Plan for a detailed description of the calculation of the Company's revenue requirement.

Q. Did the Company calculate the FY 2019 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

**Testimony of
Adam S. Crary**

PRE-FILED DIRECT TESTIMONY

OF

ADAM S. CRARY

December 21, 2017

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Adam S. Crary, 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 Department of National Grid USA Service Company, Inc. 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 1995, I graduated from Berklee College of Music in Boston, MA with a Bachelor of Music degree.

Q. Please describe your professional experience?

A For approximately eight years between 2000 and 2014, I was employed by Computer Sciences Corporation as a Pricing Analyst for their Managed Hosting and Cloud Computing business divisions, respectively. I began my employment as a Senior Pricing Analyst with National Grid in June 2014.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the proposed factors designed to recover the fiscal year (FY) 2019 revenue requirement on cumulative actual and forecasted incremental capital investment through March 31, 2019 and FY 2019 operation and maintenance (O&M) expense resulting from the Company's FY 2019 Electric Infrastructure, Safety, and Reliability (Plan) proposed in this filing and to provide the customer bill impacts of the proposed rate changes.

II. <u>INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION</u>

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

A. The Company's ISR Provision, RIPUC No. 2118, describes the process for establishing and implementing 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 O&M expense pertaining to Inspection and

Maintenance (I&M), Vegetation Management (VM) activities, and any other O&M expense as approved by the PUC.

A. <u>INFRASTRUCTURE INVESTMENT MECHANISM</u>

Q. Please describe the operation of the IIM.

A. The IIM provides for the recovery of incremental capital investment through CapEx Factors. In conjunction with the filing of the annual electric ISR Plan by January 1 of each year, the Company proposes CapEx Factors for each rate class designed to recover the cumulative revenue requirement associated with forecasted and actual capital investment through the end of the upcoming ISR Plan year ending March 31, which coincides with the Company's fiscal year. The proposed CapEx Factors become effective on and after April 1 of each ISR Plan year upon PUC approval.

Q. How are the CapEx Factors designed?

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

Next, unit rates for each rate class are developed from the allocated revenue requirement. For non-demand rate classes, a per kWh rate is calculated by dividing each rate class's share of the revenue requirement by its forecasted kWh deliveries 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 rates and are calculated by dividing the allocated revenue requirement for each rate class by an estimate of the kW billing demand for the period the rate will be in effect.

Q. Please explain why the revenue requirement is allocated using a rate base allocator.

A. A rate base allocator is used to allocate the revenue requirement associated with cumulative incremental capital investment to the Company's rate classes is similar to the manner by which the revenue requirement on capital investment would be allocated in an allocated cost of service study. Since capital investment is primarily related to plant in service, which forms the largest part of rate base, allocating the incremental capital investment using the rate base allocator contained in the allocated cost of service study in the Company's most recent general rate case is an appropriate way to spread the revenue requirement to each of the rate classes.

Q. Are the 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 submits a filing by August 1 of each year (the Reconciliation Filing) in which the Company proposes CapEx Reconciling Factors to become effective for the 12 months beginning October 1. In the Reconciliation Filing, the Company compares the revenue requirement on actual cumulative incremental capital investment to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over- or under-recovery of the this revenue requirement is credited to or recovered from customers through CapEx Reconciling Factors. The amount approved for recovery or crediting through CapEx Reconciling Factors is also subject to reconciliation with actual amounts billed through the CapEx Reconciling Factors and any difference reflected in future CapEx Reconciling Factors.

B. <u>OPERATION AND MAINTENANCE MECHANISM</u>

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

A. The O&MM provides for the recovery of the proposed O&M expense presented in the ISR Plan. The O&M Factor for each rate class are designed to recover the sum of the annual forecasted O&M expense for the upcoming ISR Plan year, as approved by the PUC in the Company's annual electric ISR Plan Filing.

Q. How are the O&M Factors designed?

A. To determine each rate class's O&M Factor, the forecasted O&M 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 PUC 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, rate and is calculated by dividing the allocated O&M expense for the combined rate class by an estimate of the kW billing demand for the 12 month period the factors are to be in effect. For all other rate classes, a per kWh rate 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 is the O&M expense 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 in an allocated cost of service study. Therefore, the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last general rate case is used to spread these costs to each of the Company's 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 rate structure for Rates G-02 and B-32/G-32 include both demand and kWh rates. The designs of the CapEx Factors and O&M Factors for these rate classes are intended to not significantly change the relationship between the existing rates 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 Factors and the O&M Factors designed as demand (per kW) rates?

A. Presently, the distribution rate structure for Rate B-62/G-62 includes only a demand charge, and the CapEx Factors 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 proposes an O&M Reconciling Factor to become effective for the 12 months beginning October 1. The Company compares the actual O&M expense to actual billed revenue generated from the O&M Factors for the applicable reconciliation period, and any over- or under-recovery of actual expense is credited to or recovered from customers through the O&M Reconciling Factor. The O&M Reconciling Factor is a uniform per kWh rate applicable to all rate classes. The amount approved for recovery or crediting through the O&M

Reconciling Factor is 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

A. CAPEX FACTORS

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

A. The CapEx Factors are designed to recover the revenue requirement related to cumulative incremental capital investment through the end of FY 2019. The revenue requirement of $20,882,134[1] is developed in the testimony of Company Witness, William R. Richer. The revenue requirement is allocated to the rate classes based on the total rate base allocator, consistent with the provisions of the general rate case Amended Settlement Agreement in Docket No. 4323, and the factors are designed as described above using forecasted billing units for the period April 1, 2018 through March 31, 2019. The calculation of the proposed CapEx Factors is set forth in Section 6, page 3 of the Plan.

B. O&M FACTORS

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

A. The proposed O&M Factors are designed to recover forecasted O&M expense for FY 2019. As developed in the testimony of William R. Richer, these expenses total

[1] *See* Section 5 of the Plan, Attachment 1, Page 1, Line 20, Column (b).

$11,872,251.[2] The Company has allocated this O&M expense using a distribution O&M allocator developed from the allocated cost of service study submitted as part of the Amended Settlement Agreement in Docket No. 4323. O&M Factors are designed as I describe above.

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 of the Plan

IV. BILL IMPACTS

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 ISR Plan. For a residential customer receiving Standard Offer Service and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $0.59, or 0.6%.

V. SUMMARY OF RETAIL DELIVERY RATES

Q. Is the Company including a revised Summary of Retail Delivery Rates tariff, RIPUC No. 2095, in this filing?

A. No, the Company is not revising this tariff at this time. The Company will submit its

[2] *See* Section 5 the Plan, Attachment 1, Page 1, Line 5, Column (b).

annual reconciliation filing in February 2018 and will propose additional rate changes for effect April 1, 2018. Therefore, the Company will submit a compliance filing following the PUC'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 effect April 1, 2018.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.