The Narragansett Electric Co. d/b/a National Grid—Application for Approval of a Change in Electric and Gas Base Distribution Rates (filed on November 27, 2017)

Docket 4770

Request for Information

Requesting Party:	New Energy Rhode Island (NERI)
To:	National Grid
Request No.:	NERI Set 12 - 2-1 through NERI 2-4
Date of Request:	3.9.18
Response Due Date:	Rolling
Subject/Panel:	Book 1—Horan

2-1. Reference p. 7. Mr. Horan speaks of change as a cost driver. In what ways might change bring savings?

Response can be found on Bates page(s) 1.

2-2. Reference the statement on p. 17, ll. 1-4, that "the Company will invest a total of $100.6 million in electric distribution infrastructure and $122 million in gas infrastructure projects, as compared to $50 million and $40 million invested in Fiscal Year 2013, respectively." Has the Company conducted the cost benefit analysis established in docket 4600 for these expenditures? If not, please describe the cost-benefit analysis, if any, that the Company conducted.

Response can be found on Bates page(s) 2-71.

2-3. Reference p. 23, ll. 7-9, stating that "The Company is proposing a return on equity of 10.1 percent at the lower end of the range of the market cost of equity determined by Mr. Hevert using his methodological approach, as he discusses in detail in his testimony." Is the Company's proposed ROE of 10.1% higher or lower than the Company's estimate of the IRR that it believes is adequate for projects developed through the REG program? If higher, why is NGrid entitled to a higher return from its customers than is needed to spur private investment?

Response can be found on Bates page(s) 72.

2-4. How does utility ownership of solar and storage projects comport with the restructuring required per RIGL 39-1-27?

Response can be found on Bates page(s) 73-74.

NERI 12-1

Request:

Subject: Book 1 – Horan

Reference p. 7. Mr. Horan speaks of change as a cost driver. In what ways might change bring savings?

Response:

On page 7 or Mr. Horan's testimony, he made the following statement:

> The impetus for change for the Company's electric business is revolving around the need to: (1) maintain a highly reliable distribution system that supports the Rhode Island economy and critical needs of individual customers; (2) adapt to changes in customer behavior and preferences caused by the transition to a digital economy and a desire to participate in climate-change response through the installation of distributed energy resources; (3) meet the aggressive goals and objectives of Rhode Island's climate-change policies, including emissions reductions; and (4) increase system resiliency to better withstand extreme weather events. The confluence of these dynamics, along with an increasing need for cyber-security, is fundamentally changing the Company's operating environment and is doing so on an unprecedented scale. Many of these changes represent important, public-interest outcomes, but are also cost drivers for the Company.

As indicated in the referenced passage above from Mr. Horan's testimony, the Company's discussion was aimed at explaining the drivers for the rate-case filing within which the Company is asking for an increase to base revenues in order to cover operating costs. The changes that are occurring in the Company's business environment are causing increases to the Company's cost of serving customers on a safe and reliable basis.

To answer the question, change may bring savings instead of cost. However, for a public utility, the opportunity to reduce operating cost in the magnitude necessary to *avoid* the filing of a base-rate case is very rare. Typically, the scale of cost savings achievable within the context of operations arising from systems implementation, procurement strategies, technology advancements or other factors, have the effect of reducing the rate of cost *growth*, but are not of the scale to reduce the cost of service on an absolute or net basis. Fundamentally, utility costs experience growth over time due to the nature of the inputs for utility service and the public-service obligations placed upon the operation.

Prepared by or under the supervision of: Timothy F. Horan and Melissa A. Little

NERI 12-2

Request:

Subject: Book 1 – Horan

Reference the statement on p. 17, ll. 1-4, that "the Company will invest a total of $100.6 million in electric distribution infrastructure and $122 million in gas infrastructure projects, as compared to $50 million and $40 million invested in Fiscal Year 2013, respectively." Has the Company conducted the cost benefit analysis established in docket 4600 for these expenditures? If not, please describe the cost-benefit analysis, if any, that the Company conducted.

Response:

The Company's recovery of capital expenditures made for electric and gas distribution infrastructure is governed by statute, and reviewed and approved by the Public Utilities Commission (PUC) each year through the Infrastructure, Safety, and Reliability (ISR) Plan dockets. The statutory framework and approved rate tariffs dictate how the costs and benefits of the ISR programs are addressed each year. By statute, the Company is required to engage with the Division of Public Utilities and Carriers (Division) on the annual plan for a period of up to 60 days.

For electric infrastructure projects, the PUC has directed the Company to submit specific pre-filing documents to the Division to inform and guide the 60-day process. Through this process, the costs, benefits, and necessity of each capital project are examined by the Division and its expert consultants.

Attachment NERI 12-2 describes the pre-filing documentation that is provided to the Division in connection with discussions between the Company and the Division each year regarding upcoming fiscal year's Electric ISR Plan. Based on the Division's recommendations for the Fiscal Year 2019 Electric ISR Plan, the Company pre-filed the documents included in Attachment NERI 12-2 with the Division on August 11, 2017. These documents include a number of specific cost/benefit analyses and studies for vegetation management, inspection and management costs, and specific capital projects for Narragansett Electric and formed the basis for the discussions between the Division and the Company. The Company also provided these documents to the PUC in the Fiscal Year 2019 Electric ISR Plan, Docket No. 4783, in response to data request PUC 1-2.

For Narragansett Electric, infrastructure investments benefit customers by maintaining the long-term safety and reliability of the electric distribution system. In making these investments, the Company considers whether any non-wires alternatives (NWAs) would provide the same level of "benefits" to the system as a traditional investment. Where all alternatives reviewed by the

Company provide the same high-level benefit, the comparison is reduced to a comparative assessment of life-cycle costs and ease of installation for the various alternatives. The alternative with the lowest overall cost and fewest installation challenges is then selected. Within this context, the cost-benefit analysis identified in Docket No. 4600 is applicable only in circumstances were a NWA and traditional wires solution are associated with a comparative set of benefits.

The process for gas infrastructure investments is different. Gas infrastructure projects are not generally subject to a cost benefit type analysis because the vast majority of gas infrastructure projects are undertaken to eliminate leak-prone infrastructure or to otherwise sustain system reliability, and are, therefore, justified on the basis of the overriding public health and safety benefit. A cost-benefit analysis is conducted for Gas Growth projects, which weighs the costs of adding the customer against future revenues from the customer addition.

Prepared by or under the supervision of: John Currie, Sonny Anand, and Ryan Constable

The Narragansett Electric Company
d/b/a/ National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2019 Proposal

Pre-filing Planning Information

Working Documents for August 31, 2017 meeting

August 11, 2017

Submitted to:
Rhode Island Division of Public Utilities & Carriers

Submitted by:
nationalgrid

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Introduction and Summary

Introduction and Summary

National Grid[1] agreed to provide electric system planning information in advance of the fiscal year 2019 (FY 2019) Electric Infrastructure, Safety, and Reliability (Electric ISR) Plan proposal. In pre-filed direct testimony dated February 16, 2017, Mr. Gregory L. Booth, PE, President of PowerServices, Inc., on behalf of the Rhode Island Division of Public Utilities and Carriers (Division), issued thirteen (13) recommendations specific to the capital investment portion of the FY 2018 Electric ISR Plan. The recommendations are as follows:

1) National Grid shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the SRP, Area Studies, ISR Plan, and internal Design Criteria.

2) National Grid shall propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at minimum:

   - The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline.
   - Discussion on the impact to related Company initiatives, PUC programs, or other requirements.
   - A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning.
   - An evaluation of potential incremental investments that support the Company's long term grid modernization strategy. This includes description of technology or infrastructure investment, cost, benefit to traditional safety and reliability objectives, and additional operational benefits achieved if implemented.
   - A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.

3) National Grid shall develop a proposal on the methodology to assign Contact Voltage program costs for the testing and remediation of elevated voltage to municipal streetlight owners.

4) National Grid shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit and present the outcome of Area Studies to the Division and its consultant at the time of completion. The Company shall submit a report with updates on modeling activities and Area Study status at least 120 days prior to filing

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

its FY 2019 ISR Plan Proposal, but in any event no later than August 31, 2017.

5) National Grid shall manage major Asset Replacement project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.

6) National Grid will continue to manage (underspend/overspend management) individual costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes South Street.

7) National Grid shall continue to provide quarterly reporting on Damage Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level 1 projects repaired as a result of the I&M program.

8) National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.

9) National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company’s Long Range Plan in advance of the FY 2019 ISR Plan proposal filing, but in any event no later than August 31, 2017.

10) National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company’s Long Range Plan, in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.

11) National Grid shall continue to submit a cost benefit analysis on the Vegetation Management Cycle Pruning Program and a separate cost benefit analysis on the Enhanced Hazard Tree Management program for the Division’s review prior to submitting the Company’s FY 2019 ISR Olan proposal, but in any event no later than August 31, 2017.

12) National Grid shall continue to submit its Metal-Clad Switchgear replacement program cost- benefit analysis to the Division prior to submitting the Company’s FY 2018 ISR Plan proposal, but in any event no later than August 31, 2017.

13) National Grid shall continue to provide quarterly confidential reports to the Division concerning the progress of negotiations with Verizon on a new Joint Ownership Agreement.

The Company has carefully reviewed the recommendations above and has addressed them in the individual sections of this document based on the understanding drawn by the original text. In instances where an interpretation to the original text was required, the Company specified its understanding of the concepts covered to facilitate the reading of the responses.

Recommendation 1

Alignment of Planning and Project Processes

Recommendation 1: Alignment of Planning and Project Processes

National Grid shall develop an alignment between various planning and project evaluation processes, with consideration as to how a grid modernization strategy may be incorporated. This includes, but is not limited to, the SRP, Area Studies, ISR Plan, and internal Design Criteria.

Alignment of Planning and Project Processes

National Grid uses a study area based approach to planning and project evaluation with additional details provided under Recommendation 4. The study process ensures alignment between issues and solutions with incorporation of existing strategies and internal design criteria. Emerging strategies, such as grid modernization, are included following measurement and verification efforts on pilot test areas or upon industry analysis demonstrating benefits. Grid modernization evaluations are ongoing and therefore have not yet been formally added to the study process. They are expected to be added in the near future. National Grid has communicated in various external stakeholder engagement sessions that a common sense approach has been used to install the latest processor based controls to enable ease of implementation of a potential pending grid modernization program. The study process document is included in Attachment Rec 1-1.

The recommendations or projects that are identified and progressed as part of the study process are included in the ISR Plan or SRP (non-wires alternatives) as appropriate. A process flowchart that shows the study based inputs to the ISR Plan or SRP is included in Attachment Rec 1-2.

Recommendation 2

System Capacity and Asset Replacement Methodology

<u>Recommendation 2: System Capacity and Asset Replacement Methodology</u>

National Grid shall propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at minimum:

- *The traditional elements included in the Company's current studies including, but not limited to, purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline.*
- *Discussion on the impact to related Company initiatives, PUC programs, or other requirements.*
- *A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning.*
- *An evaluation of potential incremental investments that support the Company's long term grid modernization strategy. This includes description of technology or infrastructure investment, cost, benefit to traditional safety and reliability objectives, and additional operational benefits achieved if implemented.*
- *A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.*

System Capacity and Asset Replacement Methodology

In order to maintain a consistent approach to distribution planning, National Grid follows uniform planning criteria and ensures that there is well executed coordination among stakeholder departments and groups. National Grid believes that the execution of a well-defined study process will result in timely delivery of infrastructure development recommendations having thoroughly defined project scopes that satisfy the needs and expectations of all stakeholders. The Company plans to improve its existing study documentation process as follows:

- Improvements to traditional study components.
    - A more detailed Executive Summary that succinctly conveys the purpose of the study and its recommendations.
    - Better consistency across studies of Introduction components including purpose and problem statements
    - Background section will specifically note each Company program and the manner in which it will be incorporated into the study.
    - Background section will include Distributed Energy Resources (DER) assumptions that will be considered in the study.
    - Problem Identification section will include a summary of relevant programmatic assessment/criticality rankings and how they refine the study efforts
    - Identification of Recommended Plan section will include a clearer description of technical and economic plan comparisons.

- Identification of regulatory programs and incorporation into the study process
    - National Grid will continue consultation with the requested external stakeholders to determine the proper incorporation of regulatory or state goals into the study process.

- Incorporation of the Company's long term grid modernization strategies
    - Emerging strategies, such as grid modernization, are included following measurement and verification efforts on pilot test areas or upon industry analysis demonstrating benefits. Grid modernization evaluations are ongoing and therefore have not yet been formally added to the study process. They are expected to be added in the near future. National Grid has communicated in various external stakeholder engagement sessions that a common sense approach has been used to install the latest processor based controls to enable ease of implementation of a potential pending grid modernization program.

- Improvement to non-wires alternatives plan development
    - Plan Development section to include details on non-wires alternative screening analysis, feasibility reviews, and scoping and estimating efforts for those cases that pass the feasibility review.

National Grid has taken recent efforts to begin the implementation of the proposed plan above by updating its study process document. Attachment Rec 1-1 includes the recent revisions.

Recommendation 3

Contact Voltage Streetlight Program

<u>Recommendation 3: Contact Voltage Streetlight Program</u>

National Grid shall develop a proposal on the methodology to assign Contact Voltage program costs for the testing and remediation of elevated voltage to municipal streetlight owners.

Contact Voltage Street Light Program

The Company developed a proposal which coordinates testing and remediation with the municipalities and requires the municipality accompany the Company during testing for elevated voltage and for the municipality to remediate any third-party asset owned by the municipality. The proposal was reviewed with the city of Providence and the Division. After review, the Company included this proposal for testing and assigning remediation costs to municipalities in its Contact Voltage Street Light Program with the FY 2017 Annual Contact Voltage filing submitted to the Rhode Island Public Utilities Commission on 07/28/2017. A copy of that filing is attached in Attachment Rec 3-1.

Recommendation 4

System Capacity Load Study
10-Year Long Range Plan

<u>Recommendation 4: System Capacity Load Study - Long Range Plan</u>

National Grid shall continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit a report with updates on modeling activities in addition to the proposed Long Range Plan (completed portions) at least 120 days prior to filing its FY 2018 ISR Plan proposal, but in any event no later than August 31, 2016. This should be continued with each subsequent ISR Plan process. There is some support for considering the planning process review as a separate activity from the ISR Plan, allowing increased efficiency in future ISR Plan process and Division review.

System Capacity Load Study - Long Range Plan

As described previously in the Company's FY 2016 Pre-filing Planning Information documents, National Grid takes a study area approach to creating a Long Range Plan (LRP). Although area studies do not provide an immediate system-wide view of all electric system issues, it is National Grid's opinion that an area study approach provides the appropriate balance between a comprehensive analysis and a focus of study efforts where most needed. Over time, through rotation and prioritization of the study areas, a system-wide view is obtained.

Attachment Rec 4-1 provides the Company's study areas, along with their current priority, area statistics, known issues and resolutions, and that status of the study. A summary of this data is included in Table 1 below. Study priority is determined by a screening method, which is led by a Company director and manager. Consideration of the number and severity of electrical issues are the primary factors in determining study priority. Secondary considerations include the area statistics (complexity) and the date of previous study efforts. The priority is reviewed and adjusted prior to the start of any new study, but at a minimum, at least once a year.

Table 1 – National Grid's Study Area Current Priority and Statistics

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# 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 Rhode Island	254	13%	35	10	50%
4	Central Rhode Island East	197	10%	38	10	**100%**
5	South County East	184	10%	21	9	85%
6	Central Rhode Island 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	
	TOTALS*	**1940**	**100%**	**392**	**103**	**56%**

National Grid's Actions Related to the LRP

The Company's study process generally follows five major steps: 1) scoping; 2) initial system assessment; 3) detailed engineering analysis; 4) plan development and estimating; and 5) identification of recommended plan. Over the past year, there have been four efforts underway with two studies completed. The four efforts, their respective study steps, and detailed sections of this document are summarized in Table 2 below:

Table 2 – National Grid's Summary of Recent Study Efforts

Study	Study Phase	Section Reference
Providence Area Study Implementation Plan	Study Complete/Submitted	Study 1
Central Rhode Island East Area Study	Study Complete/Submitted	Study 2
Northwest Rhode Island Area Study	Detailed Engineering Analysis	Study 3
South County East Area Study	Plan Development Complete	Study 4

<u>Study 1 – Providence Area Study Implementation Plan</u>

The Providence Short Term Study was completed in May 2017. A comprehensive study of the dense urban City of Providence was performed to identify existing and potential future distribution system performance concerns over a 15-year period. The study report was submitted to the Division in July of 2017. With the study completed, the resulting projects are now shown in Recommendation 4 – System Capacity Project Summary & Load Projections.

Study 2 – Central Rhode Island East Area Study

The Central Rhode Island East (CRIE) Study is a comprehensive area study addressing a variety of issues the eastern sections of the Cities of Cranston and Warwick over a 15-year period. The study was completed in February 2017 and the study report was submitted to the Division in July of 2017. The majority of this study recommendations overlap the Providence Area Study Implementation Plan and demonstrate National Grid's ability to prevent redundancy in planning

Study 3 – Northwest Rhode Island Area Study

The Northwest Rhode Island (NWRI) Area Study is expected to be completed in March of 2018 and system assessment efforts are in progress. It will be a comprehensive area study addressing a variety of issues over a 15-year period. The study will be provided as soon as it is completed. Some section summaries are included below:

Scoping

The NWRI Study Area is a combination of portions of the Blackstone Valley North and North Central Rhode Island study areas (see Table 1). This study area includes the Towns of Burrillville, North Smithfield, Smithfield, Gloucester, Scituate, Foster, and portions of Johnston. The study area contains 12 stations and 32 distribution circuits that serve approximately 200 megawatts or approximately 10% of the total state load.

System Assessment & Engineering Analysis

A preliminary review of the loading conditions for the feeders in the area was conducted. Tables 3 and 4 show a list of feeders projected to have normal loading and contingency load-at-risk issues within the study period:

Table 3 – Northwest RI Feeders – Projected Summer Normal Loading Issues

Substation	kV	Feeder	Year
Farnum Pike	12.47	23F3	2027
Nasonville	13.8	127W43	2025
Putman Pike	12.47	38F1	2023

Table 4 – Northwest RI Feeders – Projected Contingency Load-at-Risk Issues

Substation	kV	Feeder	Year
Chopmist	12.47	34F1	2016
Chopmist	12.47	34F2	2026
Chopmist	12.47	34F3	2016
Farnum Pike	12.47	23F2	2027
Manton	12.47	69F3	2024

Nasonville	13.8	127W43	2016
Putnam Pike	12.47	38F3	2016

In addition, an assessment of the condition of substation assets was conducted. Table 5 provides a summary of identified issues:

Table 5 – Northwest RI Summary of long-term asset concerns observed

Station	Inspection Comments
Valley	no major asset issues identified for the study period
West Greenville	- regulator - capacitor - airbreaks
Farnum Pike	-regulators
Wolf Hill	- 23kV breakers - airbreaks
Manton	- recloser control - abandoned wooden structure.
Centredale	- oil circuit breakers - recloser - regulator - 23kV switches and motor operators

Detailed System Assessment has been modified and extended to explore the "Heat Map" concept that will be presented in the pending 2018 System Reliability Procurement ("SRP") filing.

Study 4 – South County East Area Study

The South County East Area Study is expected to be completed in March of 2018 and plan development efforts have been recently completed. It will be a comprehensive area study addressing a variety of issues over a 15-year period. National Grid is proposing to review this study with the Division after estimates have been developed. The study section summaries are included below:

Scoping

The South County East Study Area consists of the towns of North Kingstown, South Kingstown, Narragansett and sections of East and West Greenwich, Exeter, Richmond and Charlestown. The study area has approximately 36,800 customers with a peak load of 200 MW. The area has nine substations and twenty one 12.47 kV distribution feeders. Load is a mixture of residential, commercial and industrial.

This area has a significant amount of either existing or proposed distributed generation. The area has 20.5 MW of combined heat and power natural gas generation, approximately 2.5 MW of inverter based generation, and 1.5 MW of synchronous generation. There is approximately 12.7 MW of pending inverter based generation and 30 MW of pending wind generation. Combined the existing and proposed generation totals approximately 67 MW nameplate capacity.

System Assessment & Engineering Analysis

A system assessment of the South County East area was performed to identify feeder, transformer and supply line loading concerns on the existing system; potential voltage performance issues; potential breaker short circuit duty and arc flash concerns. In addition asset condition, safety, environmental, and reliability concerns were also identified.

Some loading concerns were identified in this study. Three feeders and one substation transformer are projected to be loaded above summer normal ratings. Five feeders and one substation transformer are projected to have contingency load-at-risk exposure.

Asset issues exist mainly on the 34.5kV sub-transmission system and at the Lafayette substation. Over 60% of the 3312 line (8.6 miles) and the 84T3 line (8.7 miles) have asset issues. Each of these lines has substantial right-of-way sections which would increase direct replacement costs. The asset conditions at the Lafayette substation include one station transformer, two 34.5kV reclosers, and miscellaneous switches.

Plan Development

Three plans were developed to address existing area problems and to provide for future needs within the study area through the year 2031. Each plan provides a comprehensive solution to address all concerns in the study area. The plans are as follows:

PLAN 1 includes re-sourcing the Lafayette substation to reduce the dependence on the 34.5 kV supply and avoid supply line asset replacement. This rebuild would expand the substation from two feeders to four feeders. Plan 1 would retire approximately 16-miles of 34.5 kV sub-transmission. The station would be built with 3V0 protection and necessary relaying to accommodate both existing and future distributed generation.

PLAN 2 includes installing a new 115/12.47 kV substation near the existing Davisville station. Davisville is currently at its physical capacity and cannot be expanded further. A suitable substation land parcel would need to be acquired for this substation. The new station would be built with 3V0 protection and necessary relaying to accommodate both existing and future distributed generation. This plan also maintains the sub-transmission system and Lafayette substation in their current configurations requiring over 16 miles of line replacement and direct replacement of the Lafayette asset concerns.

PLAN 3 includes expanding Old Baptist substation with two new feeders. This plan also maintains the sub-transmission system and Lafayette substation in their current configurations requiring over 16 miles of line replacement and direct replacement of the Lafayette asset concerns.

Estimates for the three plans are being developed along with a more detail feasibility review of the substation sites. The study will also document a number of potential non-wires options to address the projected feeder overloads instead of implementing a wires solution.

Recommendation 5

Major Asset Replacement Projects Budget

Recommendation 5: Major Asset Replacement Projects Budget

National Grid shall manage major Asset Replacement project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.

Major Asset Replacement Projects Budget

The Company is currently reporting the separate spending and the updated project management status for the South Street asset replacement project in its quarterly fiscal year Infrastructure, Safety and Reliability (ISR) Reports.

Recommendation 6

Discretionary Category Portfolio

Recommendation 6: Discretionary Category Portfolio

National Grid will continue to manage (underspend/overspend management) individual costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes South Street.

Discretionary Category Portfolio

The Company is managing its ISR Plan Discretionary category budget to a separate Discretionary budget target that excludes the South Street asset replacement project. This information is reported to the Division and PUC in the Company's fiscal year quarterly ISR Reports.

Recommendation 7

Damage Failure Quarterly Reports

<u>Recommendation 7: Damage Failure Quarterly Reports</u>

National Grid shall continue to provide quarterly reporting on Damage Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level 1 projects repaired as a result of the I&M program.

Damage Failure Quarterly Reports

The Company is currently reporting on Damage/Failure expenditures for detailed projects in its quarterly fiscal year ISR Reports.

Recommendation 8

System Capacity & Performance and Asset Condition Budget Overview

Recommendation 8: System Capacity & Performance and Asset Condition Budget Overview

National Grid shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.

System Capacity & Performance and Asset Condition Budget Overview

The five-year budget overview is attached to this filing as Attachment Rec 8-1.

Recommendation 9

Asset Condition Project Summary

Recommendation 9: Asset Condition Project Summary

National Grid shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long Range Plan in advance of the FY 2019 ISR Plan proposal filing, but in any event no later than August 31, 2017.

Asset Condition Project Summary

The following Asset Condition Project Summary includes the major projects in, or to be proposed, within the Asset Condition spending rationale. At the bottom of each project summary, a statement is included regarding the projects alignment with the developing Long Range Plan.

Projects in Progress

Southeast Sub (Pawtucket No 1 Indoor Substation)

Distribution Related Project Number(s):	C053657 Southeast Sub (D-Sub) C053658 Southeast Sub (D-Line) C055683 Pawtucket No 1 (D-Sub)
Substation(s) / Feeder(s) Impacted:	Southeast 60W1, 60W2, 60W3, 60W4, 60W5, 60W6, 60W7 Pawtucket No. 1 107W1, 107W2, 107W3, 107W43, 107W49, 107W50, 107W51, 107W53, 107W60, 107W61, 107W65, 107W66, 107W81, 107W84 Pawtucket No. 2 148J1, 148J2, 148J3, 148J4 Valley St 102W51, 102W52
Voltage(s):	13.8 kV and 4.16 kV
Geographic Area Served:	Pawtucket and Central Falls
Summary of Issues:	Pawtucket No. 1 station consists of a four story brick building constructed in 1907 and an outdoor switchyard. It has nineteen 13.8 kV distribution circuits that supply 36,000 customers with 114 MW of load. Three feeders supply a network in downtown Pawtucket with approximately 3MW of load. The brick building was part of a former power plant that was decommissioned in 1975 and is less than 25% utilized. This building houses indoor distribution switchgear and other electrical equipment. The electrical equipment still in service within the building is associated with both the indoor switchgear and the outdoor yard. Some electrical equipment associated with the former power plant has been abandoned in place. The indoor substation has safety risks due to design and equipment condition. Its outmoded design no longer meets currently accepted safety practices and the equipment and protection schemes are becoming unreliable in their function of interrupting faults. The breakers in the indoor substation consist of General Electric H type oil circuit breakers ranging in age from 40 to 93 years old. These breakers are no longer supported by any vendor. A failure on these breakers has resulted in the need for a complete breaker replacement.

	The indoor substation building has numerous structural issues that are of concern for the continued safe and reliable operation of the substation. A multimillion dollar investment would be anticipated if this building was to remain. A contingency at Pawtucket No.1 involving loss of a transformer or main bus would require significant load to be transferred to adjacent stations utilizing feeder ties. Pawtucket No. 1 only has weak ties to Valley St. station, therefore a significant amount of Pawtucket No. 1 load cannot be picked up during these contingencies.
Recommended Plan	Construct a new eight feeder 115/13.8 kV metal clad station with two transformers and breaker and a half design on a site adjacent to the transmission right of way on York Avenue in the City of Pawtucket. Supply proposed station from the existing 115 kV lines crossing the site, X-3 and T-7. Rearrange the 13.8kV distribution system so that the new station supplies most of the load east of the Seekonk River. Construct a new control house at the Pawtucket No 1 substation site to house the control equipment for the 115 kV station presently located in the indoor substation building. Remove the switchgear in the indoor building and remove all the previously abandoned equipment. Demolish the indoor substation building after all electrical equipment has been removed. At Pawtucket No 1, install 3-phase metering on all feeders supplied from sections 73 and 74 located in the exterior yard which are remaining. Metered quantities shall include amps, volts, MVA and MVAR on all feeders. Total Cost = $23 million (includes all costs with transmission, distribution, operations & maintenance, and removal)
Current Status and Expected In-Service Date	Current Status – Preliminary engineering Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	Alternative 1: New Metal Clad 115/13.8 kV Station at the Pawtucket No 1 This alternative proposes development of a new 115/13.8 kV metal clad substation, breaker and a half design, in the Pawtucket No. 1 yard. The station will be constructed with two 115/13.8 kV 33/44/55 MVA LTC transformers, eight distribution circuits and two station capacitor banks. After installation of the new switchgear, load at Pawtucket No 1 will be rearranged to allow for the elimination of the 71 bus. There are presently eight circuits on section 71, including three network feeders. The three network circuits are currently dedicated feeders with approximately 3.0 MVA of peak load. It is proposed to supply these network circuits from section 73. The remaining circuits will be resupplied from the new station. Three circuits in section 73 will be resupplied from the new station to free up feeders for the three network circuits. This work will reduce loading on section 73 below the rating of the 2,000 amp bus. The distribution from Pawtucket No 1 is all underground. Therefore, new manhole and ductline infrastructure will be built from the new station out to city streets and intercept the existing underground system when practical. New underground feeder getaways will be installed from the new station and will intercept the existing cables or be routed directly to the riser poles. The existing manhole and ductline infrastructure predominantly consists of 3-inch

	conduits installed on city streets. Although the age of this infrastructure is unknown, based on the age of the indoor substation it would be reasonable to assume that the majority of this infrastructure dates back to the early 1900's. The diameter on the 3-inch infrastructure is not suitable to house the proposed solid dielectric cables required for the new feeders. New 5 inch diameter infrastructure is required for the new cable. This plan would install a new manhole and duct system to bypass the inadequate 3-inch infrastructure. Total Cost = $30.60 million (includes all costs with transmission, distribution, operations & maintenance, and removal).
Long Range Plan Alignment	Pawtucket Area Study, dated December 2014. This project is also aligned with National Grid's Strategy for Indoor Substation Rebuild and Refurbishment

South Street Substation Rebuild

Distribution Related Project Number(s):	C051212 South St Replace Indoor Substation (D-Sub) C051213 South St Replace Indoor Substation (D-Line) C055623 South St Sub 11kV Removal (D-Sub)
Substation(s) / Feeder(s) Impacted:	South Street Indoor Substation
Voltage(s):	11.5 kV
Geographic Area Served:	Providence
Summary of Issues:	South Street substation is a major 115/11 kV supply substation serving downtown Providence and surrounding area. In combination with Franklin Square 115/11 kV substation, the two substations supply a combined peak load of 148 MVA. South Street Substation replacement is driven by asset condition concerns. These concerns are described in the Asset Condition Report for the South Street Substation which is summarized in the Providence Area Long Term Distribution and Supply Study. The Asset Condition Report for the South Street substation describes issues for and recommends the replacement of a variety of station components. The building layout is such that it precludes the implementation of modern installation standards in order to replace original equipment. Additionally, spare parts for the protection components are unavailable and will be irreplaceable in the event of a failure. Lastly, maintenance work is time consuming and because of previously stated issues results in custom site-specific repairs. Specific asset condition issues exist for the transformers, breakers, switches, feeder reactors, and the battery system. Transformer concerns include past bushing failures, top cover leaks, and partial internal discharge primarily associated with the #2216 11.5 kV to 23 kV unit. A number of 11.5 kV breakers have reduced fault interrupting performance due to their outdated design. Also, replacement bushings, mechanisms and live parts for these breakers are no longer commercially available. Certain 11.5 kV gang operated switches have operational issues. In some of the bays these switches are mounted in such a manner that replacement requires both the #1 and #2 11.5 kV buses to be taken out of service. The existing reactors are the limiting elements for some feeders and cannot be replaced with similar or larger units. Lastly, the battery system is approximately 18 years old and planned for replacement.
Recommended Plan	The proposed project consists of constructing a new South Street substation on the existing South Street site, transferring all 11 kV circuits to the new substation, and removing the existing 115-11 kV substation. The 115 kV supply to the new substation will be via three new 115 kV underground cables. The cables will terminate at new structures at the Franklin Square substation, and be routed along two diverse routes to the new South Street substation. One route, for two cable circuits, will be on National Grid owned land along the Providence River. A second route, for one circuit, will be through a developer's property at Davol Square with a new easement, across South Street, along the front of the former South Street Power Station and into the new substation. An outdoor, open-air 115 kV yard will be constructed at South Street to terminate the

	three 115 kV underground cables from Franklin Square. Three new 115-11 kV, 33/44/55 MVA LTC transformers will be installed. A new substation building will be constructed, two stories tall with a basement. The second floor of the substation building will house the 11 kV switchgear for the thirty two (32) 11 kV circuit positions. The control rooms for relay protection and controls are also on the second floor. The first floor will house feeder reactors and feeder disconnect switches. The bottom floor is a basement for cable routing. The substation also includes three (3) 11 kV capacitor banks. Following the cutover of all 11 kV circuits to the new substation, the existing South Street 11 kV substation will be de-energized. The South Street 11 kV substation building will be removed following the cutover completion. The layout of the site will provide for a future 115-12.47 kV substation with two 115-12.47 kV transformers and associated 12.47 kV metal clad switchgear. All Transmission investments are expected to be Non-PTF (Non-Pool Transmission Facilities). Total Cost = $76.13 million (includes all costs with transmission, distribution, operations & maintenance, and removal)
Current Status and Expected In-Service Date	Current Status – Under Construction Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	The Providence Study notes the importance of the South St. Sub location and the need to retain the 11.5 kV supplied downtown network. With this basis and the need to address the asset conditions, the study considered a variety of station rebuild configurations. The recommended plan is the lowest cost station rebuild configuration then modified by the Study Addendum. The proposed work to underground the 115 kV lines from Franklin Square to South Street is based on a request from the developer, CV Properties, and requires a customer contribution. The National Grid project to replace South Street substation does not require these lines to be placed underground. If the developer's plans were to change, the National Grid project to replace South Street substation would proceed with the existing overhead 115 kV lines remaining in place, with the final span re-routed overhead into the new substation.
Long Range Plan Alignment	This project is aligned with National Grid's Strategy for Indoor Substation Rebuild and Refurbishment and directly recommended in the Providence Area Long Term Supply and Distribution Study, dated May 2014.

Cottage Street Substation Retirement

Distribution Related Project Number(s):	C050760 – Cottage St Substation Retirement (D-Line) C051126 – Cottage St Substation Retirement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Cottage Street – 109J1, 109J3, 109J5
Voltage(s):	4.16 kV
Geographic Area Served:	Pawtucket
Summary of Issues:	Cottage Street is a 13.8/4.16 kV substation with a single 7.0 MVA transformer supplying three feeders. It serves approximately 3,400 customers with 6.5 MW of load in the City of Pawtucket. The metal-clad switchgear at Cottage Street substation has been identified for replacement in accordance with the Metal-clad Switchgear Strategy. The metal-clad switchgear was manufactured in 1969 and therefore, the bus insulation is of an inferior design and is prone to failure. The primary driver of this project is asset condition of the metal-clad switchgear. Metal-clad switchgear manufactured prior to the 1970's comprised of paper taped bus insulation that is prone to voids and partial discharge. Additionally, gaskets become deteriorated allowing moisture into the switchgear. Metal clad switchgear of this vintage are equipped with obsolete breakers and are at a higher risk of failure. Addressing these units will reduce the risk of failure and possible customer interruptions while maintaining reliability in the area. The secondary driver is safety. Metal-clad switchgear of this vintage requires manual racking and due to warped flooring and deterioration of the metal-clad housing, it is difficult to rack breakers in and out for maintenance. In addition, compartment isolation and grounding is difficult. The new and more modern metal-clad switchgear designs have a reliable insulation system that reduces the probability of bus failures. They are manufactured such that arc flash exposure is reduced. They are equipped with remote racking devices, and have the ability to provide proper grounding and isolation for worker safety.
Recommended Plan	The recommended plan to address the concerns at Cottage Street is to retire the station. The station load will be supplied from the existing area 13.8 kV distribution system thru conversions and the use of pole mounted step-down transformers. This is the most economical approach for this area and in-line with the long term plan for this area to continue to expand the 13.8 kV distribution system. This project removes all substation equipment from Cottage Street, equipment foundations, substation yard fence and turns the site into a green field. Total Cost = $4.30 million (includes all costs with distribution, operations & maintenance, and removal) The primary driver of the cost increase was the asset condition of the existing 4kV assets. Removing the pole mounted step-down transformers from the project scope and adding conversion work was recommended by Operations and agreed to by Engineering to realize crew mobilization and outage coordination efficiencies. Without this coordination, it is expected the asset work would have been progressed in five to ten

	years requiring a repeated mobilization. Field inspections identified insufficient wire in some of the 4.16kV circuits. Company construction standards recommend upgrading all wire smaller than #3 CU during a conversion. In addition, many more poles had to be replaced than originally anticipated due to their poor condition and because pole height did not provide adequate clearances with the conversion to the 13.8 kV system. These additional 4.16 kV asset costs would have been added to the alternative as well.
Current Status and Expected In-Service Date	Current Status – Design/Engineering deferred to FY 2019 Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	The alternative plan would replace the metal-clad switchgear at the station with new more modern metal-clad switchgear. New ductline and feeder getaway cables would be installed from the new switchgear to each riser pole. Each feeder would be cutover from the existing switchgear to the new switchgear. This plan assumes there is sufficient space in the substation yard to allow for the installation of the new switchgear while maintaining the existing switchgear in service during construction. Because the cost of this plan is higher than the recommended plan, a real estate review has not been performed to determine if there is sufficient real estate to install new equipment while keeping the existing station in-service. If this alternative plan was to be implemented a full real estate and legal review should be performed. Total Cost = $2.10 million (includes all costs with distribution, operations & maintenance, and removal)
Long Range Plan Alignment	This project is aligned with National Grid’s Metal clad Replacement Strategy.

Lee Street Substation Retirement

Distribution Related Project Number(s):	C050758 – Lee St Substation Retirement (D-Line) C051118 – Lee St Substation Retirement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Lee Street – 30J1, 30J3, 30J5
Voltage(s):	4.16 kV
Geographic Area Served:	Pawtucket
Summary of Issues:	Lee Street is a 13.8/4.16 kV substation with a single 7.0 MVA transformer supplying three feeders. It serves approximately 2,586 customers with 4.10 MW of load in the City of Pawtucket. The metal-clad switchgear at Lee Street substation has been identified for replacement in accordance with the Metal-clad Switchgear Strategy. The metal-clad switchgear was manufactured in 1949 and therefore, the bus insulation is of an inferior design and is prone to failure. The gaskets are at the end-of-life and there are signs of moisture ingress and rust on the flooring. The flooring is warped making it difficult to rack the breakers in and out. One breaker is out-of-service due to a recent failure and two others have been refurbished recently due to failures. One breaker is obsolete and targeted for replacement via our Circuit Breaker and Recloser Program. The transformer is on our Watch List and is PCB contaminated. The high side of the transformer is connected to the substation supply via an oil switch contained in a metal enclosure. These enclosures have a high failure rate and are being removed from the system at every opportunity. The low side of the transformer is connected via enclosed bus, known as throat connected, and this is difficult to spare in case of an inadvertent failure. The primary driver of this project is asset condition of the metal-clad switchgear. Addressing these units will reduce the risk of failure and possible customer interruptions while maintaining reliability in the area. The secondary driver is safety. The new and more modern metal-clad switchgear designs have a reliable insulation system that reduces the probability of bus failures. They are manufactured with a robust arc resistant design, come equipped with remote racking devices, and have the ability to provide proper grounding and isolation for worker safety.
Recommended Plan	The recommended plan to address the concerns at Lee Street is to retire the station. The station load will be supplied from the existing area 13.8 kV distribution system thru conversions and the use of pole mounted step-down transformers. This is the most economical approach for this area and in-line with the long term plan for this area to continue to expand the 13.8 kV distribution system. This project removes all substation equipment from Lee Street, foundations, substation yard fence and turns the site into a greenfield. Total Cost = $3.10 million (includes all costs with distribution, operations & maintenance, and removal) The primary driver of the cost increase was the asset condition of the existing 4 kV assets. Removing the pole mounted step-down transformers from the project scope and

	adding conversion work was recommended by Operations and agreed to by Engineering to realize crew mobilization and outage coordination efficiencies. Without this coordination, it is expected the asset work would have been progressed in five to ten years requiring a repeated mobilization. Field inspections identified insufficient wire in some of the 4.16 kV circuits. Company construction standards recommend upgrading all wire smaller than #3 CU during a conversion. In addition, many more poles had to be replaced than originally anticipated due to their poor condition and because pole height did not provide adequate clearances with the conversion to the 13.8 kV system. These additional 4.16 kV asset costs would have been added to the alternative as well.
Current Status and Expected In-Service Date	Current Status – Design/Engineering deferred to FY 2019 Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	The alternative plan would replace the metal clad switchgear at the station with new more modern metal-clad switchgear. The transformer would be replaced with a conventional transformer (throat connection would be removed), and the high side oil switch would be removed and replaced with a high side recloser. New ductline and feeder getaway cables would be installed from the new switchgear to each riser pole. Each feeder would be cutover from the existing switchgear to the new switchgear. This plan assumes there is sufficient space in the substation yard to allow for the installation of the new switchgear and transformer while maintaining the existing station in service during construction. Because the cost of this plan is significantly higher than the recommended plan, a real estate review has not been performed to determine if there is sufficient real estate to install the new equipment while the existing station remains in-service. If this alternative plan was to be implemented a full real estate and legal review should be performed. Total Cost = $2.96 million (includes all costs with distribution, operations & maintenance, and removal)
Long Range Plan Alignment	This project is aligned with National Grid's Metal clad Replacement Strategy.

Westerly Flood Restoration

Distribution Related Project Number(s):	C036527 – Westerly Flood Restoration (D-Line) C055215 – Westerly Flood Restoration (D-Sub)
Substation(s) / Feeder(s) Impacted:	Westerly – 17F1, 17F2, 17F3, 17F4
Voltage(s):	34.5 kV and 12.47 kV
Geographic Area Served:	Westerly
Summary of Issues:	Westerly is a 34.5/12.47 kV substation equipped with two 20 MVA transformers that supply four distribution feeders. The station supplies 9,200 customers with a peak load of 36 MW in the Town of Westerly. The voltage in this station does not phase with the rest of the system in the area. Therefore, before switching Westerly feeders to other stations customers are exposed to a short duration outage. Westerly substation is located in close proximity to the Pawcatuck River. In March 2010 flooding occurred in this area and flood waters peaked at approximately six feet in the substation yard. All the equipment in the substation yard and inside the control house was damaged. All roads leading to the substation were impassable and access to the station was only possible on and after April 1, 2010. Once flooding conditions subsided, a mobile substation was sited and energized on Perkins Avenue in Westerly to pick up interrupted customer load. Additional load was restored using distribution feeder ties to other stations and an emergency pad-mounted transformer was installed on RIDOT owned property near existing 34.5 kV and 12.47 kV distribution infrastructure. In preparation for the 2010 summer peak load, portions of Westerly substation were placed back in service in May and June. Because Westerly substation was only partially restored, supplying load in Westerly over the summer was challenging and resulted in the need to shed customer load to maintain equipment operating safely within its rated capability. To mitigate the need to continue to shed load, roll-in generation was installed while Westerly substation was being restored to full operation. By mid-summer 2010, permanent repairs were made at Westerly substation and the roll-in generation was removed along with the emergency pad-mounted transformer. To mitigate future flood damage risk at Westerly substation, a long-term plan was developed in 2010. The plan recommended abandoning the Westerly substation site and expanding the proposed Hopkinton substation that was being permitted in the Town of Hopkinton on company owned land west of route 3. The recommendation was to install a second power transformer and four additional feeders at Hopkinton substation. This investment would provide capacity to retire Westerly substation. The company was not successful in permitting the substation site located west of route 3 due to opposition from the Town of Hopkinton. After extensive negotiations with the Town, a site suitable for substation construction was identified east of route 3 and acquired by the company. The zoning ordinance has been amended by the Town to allow for substation construction on this site. The new site is located near the intersection of Ashaway and Chase Hill Road and is referred to as the Chase Hill substation site. The new site resulted in greater than anticipated distribution line costs and right-of-way

	construction and maintenance challenges. The site is further away from the Westerly load center as compared to the original site. While the additional distribution distance was considered in the decision to move to the new site, further design reviews identified significant increased right-of-way construction costs. A more comprehensive review by operations also identified challenges with access, initial construction, and long-term maintenance of distribution circuits on the right-of-way. Due to the aforementioned challenges, the strategy to install 8-feeders at the Chase Hill substation site has been modified to only install 4-feeders. The 4-feeders removed from the Chase Hill scope will be replaced by 4-feeders to be supplied from a rebuilt Westerly substation. Rebuilding Westerly substation is more economical as compared to expanding Chase Hill substation and results in shorter distribution feeders which reduces mainline exposure and improves reliability.
Recommended Plan	The following work is required at Westerly substation to mitigate the risk of future flood damage, increase the supply capacity to Westerly, and correct area phasing challenges to improve reliability. Purchase and install the following major equipment: Two 34.5 kV circuit switchers. Two 34.5 kV/13.2 kV 20/30/40 MVA LTC delta zigzag transformers. New 15kV metal-clad breaker and half switchgear with breakers for six feeders and two capacitor banks. Initial construction will consist of four feeders. Two 2-stage open air 7.2 MVar cap banks (3.6 MVar per stage) Once the new station is cutover all the equipment in the old yard shall be removed Total Cost = $7.64 million (includes all costs with distribution, operations & maintenance, and removal)
Current Status and Expected In-Service Date	Current Status – Design/Engineering deferred to FY 2019 Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	Alternative 1: Expand Chase Hill Substation This alternative proposes continuing with the existing strategy to expand Chase Hill substation by installing a second 40 MVA power transformer and 4-additional distribution feeders. The estimated cost of this alternative is $11 million. This alternative is not recommended by the Company for the following reasons: It has a higher cost than the preferred plan ($11 million vs. $10 million). The Chase Hill site is remote from the Westerly load center resulting in significant right-of-way construction for the distribution feeders. Additional investigation by design and operations to build feeders on the right of way has identified significant challenges with access, initial construction, and long-term maintenance of these circuits. There is no economic or reliability benefit to supplying Westerly load from Chase Hill substation. Feeders supplied from a rebuilt Westerly substation will be much shorter resulting in significant less mainline exposure and improved reliability.
Long Range Plan Alignment	This project is aligned with National Grid's Flood Risk Mitigation Strategy. Note the recommended plan revision listed under the Chase Hill Project (capacity).

Recommendation 10

System Capacity Project Summary and Load Projections

Recommendation 10: System Capacity Project Summary & Load Projections

National Grid shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan, in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.

System Capacity Project Summary & Load Projections

The following System Capacity Project Summary includes the major projects in or to be proposed within the System Capacity and Performance spending rationale. At the bottom of each project summary, a statement is included regarding alignment with the developing Long Range Plan. Load projections are included in Attachment Rec 10-1.

Projects in Progress

Chase Hill (Hopkinton) Substation

Distribution Related Project Number(s):	C024175 Chase Hill Substation (D-Line) C024176 Chase Hill Substation (D-Sub) C034102 Retire Ashaway Substation C036233 Retire Hope Valley (D-Sub) C036234 Retire Hope Valley (D-Line)
Substation(s) / Feeder(s) Impacted:	Chase Hill (Hopkinton) – 155F1 thru 155F4 Ashaway - 43F1 Hope Valley – 41F1 Langworthy – 86F1 Kenyon – 68F3 Westerly – 16F1, 16F2, 16F3, 16F4
Voltage(s):	12.47 kV
Geographic Area Served:	Hopkinton, Westerly, Charlestown, Richmond
Summary of Issues:	Facility loading (normal and contingency) and outage exposure concerns were originally identified in 2007 and reconfirmed in 2009 and 2011. These concerns included transformers and feeders projected to be loaded above their summer normal rating. Ashaway and Hope Valley substations have numerous asset condition concerns that need to be addressed. These asset issues are addressed within the solution to the capacity issues described above in a comprehensive manner.

Recommended Plan	The project consists of constructing a new metal-clad substation on a newly acquired site in Hopkinton, R.I. The site is adjacent to an existing 115 kV transmission Right-of-Way. The project includes the installation of one 40 MVA transformer and four (4) new distribution feeders. The project retires Ashaway and Hope Valley substations to address the asset condition concerns. Total Cost = $24.33 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes).
Current Status and Expected In-Service Date	Current Status – Construction Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	<u>Alternative 1:</u> Similar to the recommended plan, Alternative 1 addresses the Load Relief and Flood Risk Mitigation issues. <u>Load Relief</u>: This alternative recommended the reinforcement and expansion of the existing 34.5 kV supply and 12.47 kV distribution system. This would require replacement of both Wood River transformers, replacement of both Westerly supply transformers, development of the Westerly 16F5 and 16F6 feeders, and upgrades to the Wood River supply lines. This plan was estimated to cost $11 million (2006 dollars).
Long Range Plan Alignment	The Chase Hill Substation Project combined with the Westerly Flood Restoration Project resolve the capacity and asset condition issues in this area for a number of years. As a result, re-study of this area can be deferred.

New London Ave (West Warwick) Substation

Distribution Related Project Number(s):	C028920 New London Ave (Dist Sub) C028921 New London Ave (Dist Line)
Substation(s) / Feeder(s) Impacted:	New London Ave (West Warwick) – 150F1, 150F3, 150F5, 150F7 Anthony - 64F1, 64F2 Arctic - 49J1, 49J2, 49J3, 49J4 Drumrock – 14F3, 14F4 Hope – 15F1, 15F2 Hopkins Hill – 63F2, 63F5, 63F6 Kent County – 22F3, 22F4 Natick – 29F1
Voltage(s):	12.47 kV
Geographic Area Served:	Warwick, West Warwick, Coventry, West Greenwich
Summary of Issues:	This area is supplied by a highly utilized supply and distribution system. It is becoming increasingly challenging to operate this system within normal loading limits and to supply load growth in this area. This project provides a long-term solution for the area. The driver for the project is projected thermal overloads of transformers, distribution feeders and supply lines during periods of system peak loading. There have been a number of large developments in the area such as The Centre of New England and the Royal Mills complex that continue to add load to an area with heavily loaded feeders, transformers and supply lines. O&M services performed an assessment of the Arctic substation equipment. Assessment identified equipment condition, safety, and environmental concerns at this station. Arctic is a 1940's vintage station supplying 2,430 customers. It is supplied by a highly utilized sub-transmission system and is the only station supplying 4.16 kV distribution in the area while the rest of the distribution is supplied by a 12.47 kV system. This small pocket of 4.16 kV load has no ties to any other substation.
Recommended Plan	The project consists of a new metal clad substation with a 40 MVA transformer with an ultimate capacity of five feeder positions in West Warwick, RI. The station will be located adjacent to an existing 115 kV transmission corridor. Initially, four 12.47 kV feeders will be installed and the distribution system will be rearranged to offload existing transformers, supply lines and distribution feeders. Project retires Arctic substation to address equipment condition, safety, and environmental concerns with the station. Total Cost = $18.45 million (includes all costs with transmission, distribution, operations & maintenance, and removal values.) The total cost includes distribution line asset condition work identified during detailed design. This asset condition work of $4.0 million is common to all plans and can be excluded for alternative comparison purposes. For alternative comparison, the total cost of the recommended plan is $14.6 million.

Current Status and Expected In-Service Date	Current Status – Construction Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	Alternative 1: This alternative involved the expansion of existing 115/12.47 kV substations at West Cranston and Kent County and expansion of the 23 and 34.5 kV supply systems at Drumrock and Kent County substations to address the capacity issues and the rebuild of the Arctic Substation to address asset condition issues. The supply lines would be rebuilt for a larger capacity to accommodate two new modular stations in West Warwick and Coventry. It would be necessary to procure sites with the appropriate zoning for each station. The distribution system would be modified to accommodate the new stations. The estimated cost of the capacity related work is $15.10 million. The Arctic Substation rebuild work is estimated at $3.0M, for a total alternative cost of $18.0 million. This option exceeded the cost of the preferred option; there are no additional benefits; and the uncertainty of finding appropriate lots make this option unattractive at this time. Alternative 2: This alternative involved the development of a new 115/12.47 kV metal clad station on a site in Cranston near Phoenix Avenue. The transmission costs are similar to the preferred plan but the distribution costs to extend feeders from this site to relieve the overloaded feeders and supply lines would be significantly more due to the limited routes available and the distance from the overloaded facilities. The details of this option were not fully developed as the estimated distribution costs far exceeded those of the preferred alternative which was near the stations with loading issues.
Long Range Plan Alignment	The project addresses a portion of the capacity and asset condition issues in the Central RI West study area. It is expected this area will be restudied in 1 to 3 years.

Aquidneck Island (Newport & Jepson Substations)

Distribution Related Project Number(s):	C015158 Newport Substation (D-Sub) CD00649 Gate 2 Substation (D-Sub) C028628 NEWPORT Load Relief - Phase 2 (D-Line) C024159 Newport 69kV Line 63 (D-Line) CD00651 Bailey Brook Retirement (D-Sub) CD00652 Vernon Retirement (D-Sub) CD00656 Jepson Substation (D-Sub) C054052 No Aquidneck Retirement (D-Sub) C058310 Harrison Sub Improvements (D-Sub) C058401 Merton Sub Improvements (D-Sub) C058404 Kingston Sub Improvements (D-Sub) C058407 South Aquidneck Retirement (D-Sub) C054054 Jepson Substation (D-Line)
Substation(s) / Feeder(s) Impacted:	Newport – 203W1, 203W2, 203W3, 203W4, 203W5 Bailey Brook – 19J2, 19J14, 19J16 Gate II – 38J2, 38J4 Hospital – 146J2 Jepson – 37J2, 37J4, 37W41, 37W42, 37W43 Kingston – 131J4, 131J6, 131J12, 131J14 North Aquidneck – 21J2, 21J6 South Aquidneck – 122J2, 122J4, 122J6 Vernon – 23J2, 23J4, 23J6, 23J12, 23J14 West Howard – 154J4
Voltage(s):	13.8 kV & 4.16 kV
Geographic Area Served:	Newport, Middletown, Portsmouth
Summary of Issues:	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. It is becoming increasingly challenging to supply large spot loads in southern Middletown and in the City of Newport. The Jepson 13.8 kV system has been utilized to provide relief to the 23 kV supply system, the 4.16 kV distribution system, and to supply large spot loads. However, this 13.8 kV system has been extended to its limits. For loss of the Jepson 13.8 kV system, the 13.8 kV supplied load in the City of Newport will be out until Jepson is placed back in service. For loss of the Dexter 115/13.8 kV transformer on peak up to 13 MW of load on Aquidneck Island (primarily in Portsmouth) would remain un-served until the transformer is replaced or a mobile is installed. This results in an exposure of approximately 350 MWh. For loss of the Jepson 69/13.8 kV transformer on peak up to 17 MW of load on Aquidneck Island (primarily Middletown and the City of Newport) would remain un-served until the transformer is replaced or a mobile is installed. This results in an exposure of approximately 460 MWh. For loss of the 69 kV line section between Jepson and the Navy substation on peak up to 18 MW of load would remain un-served. Either Navy load would be un-served or a large portion of the City of Newport load would be un-served. This results in an

	exposure of approximately 500 MWh. Equipment concerns exist at the Jepson 4.16 kV substation. A condition evaluation of these assets was completed in 2005 which identified concerns with the 4.16kV station regulators and the 37J4 recloser. Regulators do not meet clearance requirements and are located before the breakers. A regulator failure results in loss of the Jepson 4.16 kV station. In addition, both feeders need to be removed from service to perform any regulator maintenance making operating the 4.16 kV station challenging. Bailey Brook substation is located within local wetlands and adjacent to a running brook that is a source of the water supply for the island. The retirement of Bailey Brook will eliminate the potential of an oil spill into the brook and the islands water supply and the potential of the substation being damaged due to flooding. Vernon substation has numerous asset condition concerns. The Vernon metal-clad switchgear was installed in 1949 along with the TR231 transformer. The TR232 transformer was installed in 1963. All the station breakers have been identified for asset replacement along with the TR231 transformer.
Recommended Plan	This recommended plan is depended on the effort to convert the transmission supply to the Jepson substation from 69 kV to 115 kV. This transmission effort is separate and is not included in the cost estimates or alternative analysis below. The distribution project consists of installation of a new 69/13.8 kV substation in Newport consisting of one (1) transformers supplying metal-clad switchgear, installation of four (4) 13.8 kV feeders, installation of a new 115/13.8 kV substation at Jepson consisting of 2-40 MVA transformers and six (6) feeders, and reconfigure the area distribution system. This project allows retirement of the 4.16 kV substations at Jepson, Bailey Brook, N. Aquidneck, S. Aquidneck, and Vernon substations to address asset condition concerns and provide routes for new 13.8 kV feeders. Total Cost = $66 million (includes all costs with distribution, operations & maintenance, and removal values for alternative comparison purposes)
Current Status and Expected In-Service Date	Current Status – Various – Phases of this project are in Design/Engineering, Permitting and Construction. Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	<u>Alternative 1 ($65 million)</u>: This plan proposes to install a new 69/13.8 kV substation in Newport consisting of two (2) transformers supplying metal-clad switchgear with eight (8) 13.8 kV feeders positions with five feeders being initially installed. The substation would be served from an existing 69 kV line and a new 69 kV underground 4 mile transmission line from the Jepson substation. The estimated cost of this alternative is $65 million due to the increased cost to build the underground 69 kV line. This plan maintains the overhead facilities installed on both sides of West Main Road in Middletown and would not reduce the congestion that currently exists in the area. This plan is not recommended due to the incremental cost to install an underground transmission line and because it offers no reliability improvement over the recommended plan.

Long Range Plan Alignment	The Newport Substation Project, combined with the Clarke St Project resolves the capacity and asset condition issues in this area for a number of years. Consequently, re-study of this area can be deferred.

Quonset Substation Expansion

Distribution Related Project Number(s):	C053646 Quonset Substation Expansion (D-Sub) C053647 Quonset Substation Expansion (D-Line)
Substation(s) / Feeder(s) Impacted:	Davisville – 84T1, 84T2, 84T3, 84T4 Quonset - 83F1, 83F2, 83F3 Old Baptist – 46F4 Tower Hill – 88F7
Voltage(s):	34.5 kV, 12.47 kV
Geographic Area Served:	North Kingstown
Summary of Issues:	Quonset substation is projected to supply 19 MW of load in 2014. It is a single transformer station with a single feeder tie to other stations. For loss of the station transformer on peak approximately 5 MW of load can be picked up thru this feeder tie leaving 14 MW of un-served load. A large industrial customer in Quonset Point has begun a multi-phase multi-year expansion in the area which is projected to add 16 MW of new load. The bulk of this expansion is projected to occur in 2014 and 2015 with the rest projected to occur in 2019 and 2021. The majority of the new load will be supplied from the Quonset 12.47 kV system and the remainder directly from Davisville 34.5 kV system. The expansion will increase the load at Quonset substation to 27 MW. This will result in the station transformer being loaded above its rated capability. In addition, the projected loading of 27 MW will increase the un-served load risk to 22 MW for loss of the station transformer. To resolve the projected overload and the load at risk, new supply and distribution capacity is required.
Recommended Plan	This project consists of the installation of a second 40 MVA power transformer and one new feeder, 83F4, at Quonset Point substation. This work addresses the contingency issues and provides capacity for the growing commercial and industrial load. Total Cost = $8.96 million (includes all costs with distribution, operations & maintenance, and removal values for alternative comparison purposes)
Current Status and Expected In-Service Date	Current Status – Construction Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	Alternative 1: Install a new Metal Clad 115/12.47 kV Substation at Davisville This alternative proposes development of a new 115/12.47 kV metal clad substation, straight bus design, in the existing Davisville substation yard. The station design would be for two 115/12.47 kV 24/32/40 MVA LTC transformers, eight distribution circuits and two station capacitor banks. Initial construction would consist of a single transformer, three feeders, and one station capacitor bank. A one line of the proposed substation is shown in Figure 4.

	The existing land parcel at Davisville substation is 6.1 acres and houses the 115/34.5 kV Davisville substation. Although the parcel has some wetlands, a preliminary review indicates the site has enough land to house the proposed 115/12.47 kV substation. This plan transfers load from Quonset substation to the new station and relieves the Davisville 34.5 kV system. The estimate cost of this plan is $8 million.
Long Range Plan Alignment	The project in aligned with the Quonset Point Study.

East Bay Study Phase 1 – East Providence & Warren Substations

Distribution Related Project Number(s):	C046726 East Providence Substation (D-Sub) C046727 East Providence Substation (D-Line) C065166 Warren Substation Expansion (D-Sub) C065187 Warren Substation Expansion (D-Line) C065293 Barrington Sub Retirement (D-Sub) C065295 Kent Corners Retirement (D-Sub) C065297 Waterman Ave Retirement (D-Sub)
Substation(s) / Feeder(s) Impacted:	Wampanoag – 48F1, 48F2, 48F3, 48F4, 48F5, 48F6 Warren – 5F1, 5F2, 5F3, 5F4 Phillipsdale – 20F1, 20F2 Waterman Avenue – 78F3, 78F4 Kent Corners – 47J2, 47J3, 47J4
Voltage(s):	12.47 kV, 4.16 kV
Geographic Area Served:	City of East Providence and the town of Warren
Summary of Issues:	A study of the East Bay area was performed to identify feeder, transformer and supply line loading concerns on the existing system; potential voltage performance issues; potential breaker short circuit duty and arc flash concerns. Asset condition, safety, environmental, and reliability concerns have also been investigated. A number of concerns were identified as a result of the study. The feeders originating from the Phillipsdale and Waterman substations provide limited capacity flexibility because they do not phase with rest of the system in East Bay. Excluding these out of phase feeders and the small pocket of 4.16 kV load, by 2026, approximately 70% of the feeders are projected to be loaded above 90% of summer normal rating and four feeders are projected to be loaded above 100% of summer normal rating. Several asset conditions concerns were also identified at the Barrington, Kent Corners, Phillipsdale, Warren, and Waterman Avenue stations and throughout the 23 kV sub-transmission system. The primary driver for these projects is system capacity and performance including normal and contingency load relief issues. However, as a result of the comprehensive nature of the East Bay Area Study, each project has a secondary asset condition driver. The full analysis of the drivers and how each project addresses the comprehensive system needs is described within the study. Phase 1 of the East Bay Study primarily addresses issues in the East Providence and Warren areas.

Recommended Plan	The Phase 1 of the study recommended plan includes building two new substations supplied from the 115 kV transmission system. System rearrangement proposed within this plan reduces loading and dependence on the 23 kV sub-transmission system. The following are the major modifications proposed: • Build 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. • Expand the existing 115/12.47 kV substation at Warren by installing two new 12.47 kV distribution feeder positions and a two-stage 7.2 MVAR capacitor bank on each bus. • Retire a number of substations in the study area and remove all equipment and foundations to below grade. The station retirements are Barrington substation; Kent Corners substation; Waterman substation; and the 2291 Line position at Warren substation. Total Cost = $27.22 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes).
Current Status and Expected In-Service Date	Current Status – Design/Engineering Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	The comprehensive recommended plan from the East Bay study had a total cost of $37.7 million. The alternatives described below were compared against this comprehensive plan: <u>Alternative 1</u>: This plan includes adding new distribution capacity supplied from an upgraded 23 kV subtransmission system and has limited investment in expansion of the 115 kV transmission system. The following are the major modifications proposed: • Replace the existing 23/4.16 kV substation at Kent Corners with two 23/12.47 kV modular feeders supplied from an upgraded 23 kV system. The sub-transmission upgrades require approximately 7.5 miles of line reconductoring along a public roadway system. • Build two new 23/12.47 kV modular feeders on a Company owned site in East Providence. This was the location of Rumford substation which was retired and removed in the 1990's. • Replace the existing out of phase 23/12.47 kV substation at Phillipsdale with two new 23/12.47 kV modular feeders. The new feeders would phase with the rest of the distribution system in the area. • Build a new 115/23 kV substation at Mink Street to supply the reinforced, upgraded, and expanded 23 kV system. Construction would consist of a single 40 MVA

	transformer supplying a single 23 kV line. • Address asset condition concerns at Phillipsdale and Warren 115/23 kV substations. These two stations, along with Mink Street, will supply the 23 kV system. Total Cost = $50 million includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes) <u>Alternative 2</u>: This plan includes expanding the 115 kV transmission system along with expanding and reinforcing the 23 kV sub-transmission system. The following are the major modifications proposed: • Replace the existing out of phase 23/12.47 kV substation at Phillipsdale with a new 115/12.47 kV station. 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. • Build a new 115/23 kV substation at Mink Street to supply the reinforced, upgraded, and expanded 23 kV system. Construction would consist of a single 40 MVA transformer supplying a single 23 kV line. • Replace the existing 23/4.16 kV substation at Kent Corners with two 23/12.47 kV modular feeders supplied from an upgraded 23 kV supply system. The sub-transmission upgrades require approximately 7.5 miles of line reconductoring along a public roadway system. • Address asset condition concerns at Warren 115/23 kV substation. This station, along with Mink Street, will supply the 23 kV system. Total Cost = $41.20 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes)
Long Range Plan Alignment	East Bay Study (August 2015).

Providence Study Phase 1 – Admiral Street Substation

Distribution Related Project Number(s):	C077365 – Clarkson St 13F10 - Hawkins St (D-Line) C077368 – Olneyville 6J5 Feeder Retirement (D-Line) C078734 – Admiral St 4 kV & 11 kV Retirement (D-Line) C078796 – Admiral St 11 kV Rochambeau Supply (D-Line) C078800 – Clarkson St & Lippitt Hill 12 kV Rebuilds (D-Line) C078802 – Olneyville 6J1, 6J3, 6J6, 6J7 Feeder Retirement (D-Line) C078811 – Geneva, Olneyville, Rochambeau 4 kV Retirement (D-Line) C078857 – Harris Ave 4 kV & 11 kV Retirement (D-Line) C078805 – Knightsville 4 kV Retirement (D-Line) C078810 – Harris Ave 1129 and 1137 Retirement (D-Line) C078803 – Admiral St 12 kV MH & Duct (D-Line) C078804 – Admiral St 12 kV Cables (D-Line) C078797 – Admiral St Rochambeau Supply (D-Sub) C078735 – Admiral St 115/12.47 kV (D-Sub) C078806 – Knightsville 23/12 kV (D-Sub) C078801 – Admiral St Building Demolition (D-Sub) C078847 – Geneva 4 kV Removal (D-Sub) C078849 – Harris Ave 4 kV & 11 kV Removal (D-Sub) C078850 – Olneyville 4 kV Removal (D-Sub) C078851 – Rochambeau 4 kV Removal (D-Sub)
Substation(s) / Feeder(s) Impacted:	Admiral Street 9J1, 9J2, 9J3, 9J5, 1115, 1117, 1119 Clarkson Street 13F1, 13F2, 13F3, 13F5, 13F6, 13F7, 13F8, 13F9, 13F10 Lippit Hill 79F1, 79F2 Point Street 76F3, 76F4, 76F5 Dyer Street 2J3 Geneva 71J1, 71J2, 71J3, 71J4, 71J5 Olneyville 6J1, 6J2, 6J3, 6J5, 6J6, 6J7, 6J8 Knightsville 66J1, 66J2, 66J3, 66J4, 66J5 Harris Avenue 12J1, 12J2, 12J3, 12J4, 12J5, 12J6, 1129, 1131, 1133, 1137, 1145, 1147 Rochambeau Avenue 37J1, 37J2, 37J3, 37J4, 37J5 Johnston 18F5, 18F7, 18F9
Voltage(s):	12.47 kV, 11.5 kV, 4.16 kV
Geographic Area Served:	City of Providence
Summary of Issues:	Providence is an urban area with a relatively concentrated load. The electrical distribution facilities consist of a mix of older 11 kV and 4.16 kV distribution systems and a newer 12.47 kV distribution system. The distribution circuits are primarily underground in the downtown business district whereas they are overhead in the surrounding residential areas. Much of the underground infrastructure dates back to the period when the system was originally installed in the 1920's. The study identified the main issue to be asset condition. Six of the older stations supplying the area are indoor stations installed between 1924 and 1939 and have a number of asset related concerns. The health and condition of all indoor stations were assessed and each station assigned a priority score. In addition to the station issues, over 25 miles of underground supply and distribution circuits were identified in the Company's cable replacement program. Although asset condition was the main driver, the study also identified some loading, contingency loading, and breaker duty issues.

Recommended Plan	The Providence Study assessed various options to resolve issues identified within the study area and compared the economics of several supply and distribution alternatives. The preferred option recommended the expansion of the 12.47 kV distribution system, conversion of the majority of 11.5 kV and 4.16 kV load to 12.47 kV and elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations. The majority of the new 12.47 kV capacity in the recommended plan would be provided by new 115/12.47 kV stations at Admiral Street, Auburn and South Street. The first phase of alternate analysis was considered in Part A of the Providence Long Term Study. The alternative plans considered in Part A include the items below compared against one for one asset replacement. The purpose of Part B of the Providence Area Study was to create a sequencing of the items recommended in Part A.: • Install a new 23/11 kV transformer at Admiral Street substation to supply Rochambeau Avenue substation. • Convert Admiral Street 11.5 kV and 4.16 kV feeders to 12.47 kV and retire stations. • Demolish the Admiral Street indoor substation and prepare site for new 115/12.47 kV substation. • Build new Admiral Street 115/12.47 kV metal clad substation with four feeders. • Convert the Olneyville 4.16 kV feeders to 12.47 kV and retire the substation. • Install a modular 23/12.47 kV feeder position at Knightsville and convert Knightsville 4.16 kV feeders to 12.47 kV. • Convert Harris Avenue 11.5 kV and 4.16 kV feeders to 12.47 kV and retire substation. • Convert Geneva 4.16 kV feeders to 12.47 kV and retire the substation. • Convert Rochambeau Avenue 4.16 kV feeders to 12.47 kV and retire substation. • Convert Sprague Street and Huntington Park 4.16 kV feeders to 12.47 kV and retire both substations. Total cost for the plans presented above is $81 million.
Current Status and Expected In-Service Date	Current Status – Design/Engineering starts FY 2019 Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	The alternative analysis for the Admiral Street plan was completed within the Part A study. Part A considered direct one for one replacement of the significant asset issues including complex indoor substation rebuilds and over 25 miles of sub-transmission and distribution cable replacement with an estimated cost over $97 million.
Long Range Plan Alignment	Providence Area Study Implementation Plan 2016 – 2030 (May 2017).

Recommendation 11

Vegetation Management Cost-Benefit Analysis

Recommendation 11: Vegetation Management Cost-Benefit Analysis

National Grid shall continue to submit a cost-benefit analysis on the Vegetation Management Cycle Pruning Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management program for the Division's review prior to submitting the Company's FY 2019 ISR Plan proposal, but in any event no later than August 31, 2017.

Vegetation Management Cost-Benefit Analysis

Introduction and Summary

In the Rhode Island Public Utilities Commission's (Commission) Report and Order issued on May 3, 2012 on the Company's FY 2013 Electric ISR Plan, which was approved by the Commission effective March 29, 2012 pursuant to an Open Meeting decision, the Commission directed the Company to collaborate with the Division to develop a method by which the costs and benefits of the Vegetation Management Program and Inspection and Maintenance Program be tracked and reported in future ISR filings.[2]

National Grid met with the Division and its consultant, Mr. Gregory Booth on June 15, 2012 to collaboratively develop a method for the tracking and reporting of costs and benefits for both the Vegetation Management Program and Inspection and Maintenance Program. The description and method for each of these programs was filed with the Commission on June 29, 2012.[3]

With respect to the Vegetation Management Program, the Company agreed to:

1. Quantify the reliability benefits for both the Enhanced Hazard Tree Mitigation (EHTM) and the Cycle Pruning Programs on a fiscal year basis with the benefits determined by comparing a pre-project three year average to a post-project tree related number of customers interrupted and the costs calculated by a cost per feeder to calculate an overall cost per change in customer interruptions; and

2. Perform a Damage Restoration Cost Benefit analysis for the EHTM Program circuits using a similar method, and estimate the costs of restoration.

The first Vegetation Management Program cost-benefit analyses were filed with the Commission on September 5, 2012. This constitutes the sixth filing and includes work performed in FY 2016.

As set forth below, Section 1 provides the Company's results of the FY 2016 Reliability Cost-Benefit for the EHTM and Cycle Pruning Programs. Section 2 provides the results of the Company's Damage Restoration Cost-Benefit for the EHTM Program.

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2 Docket No. 4307, Report and Order, page 16. The Inspection and Maintenance Cost Benefits Study is provided separately.

3 Docket No. 4307 compliance filing of June 29, 2012, page 1.

Section 1 – FY 2016 Reliability Cost-Benefit for the EHTM and Cycle Pruning Programs

To meet the requirements of the FY 2012 Electric ISR Plan, the following study of the Company's Vegetation Management Program has been performed annually since FY 2012. The analysis was done for the work performed in FY 2008 through FY 2016 for the Enhanced Hazardous Tree Maintenance (EHTM) Program and FY 2007 through FY 2016 for the Cycle Pruning Program. To calculate the reliability benefits of the EHTM and Cycle Pruning Programs, the Company used the average number of tree-related customer interruptions (CI's) over a three year period prior to the project year as the baseline. The project year was excluded from the analysis as both the EHTM Program and the Cycle Pruning Program often take the majority of the fiscal year to complete. Tree-related CI's were then calculated for the first full year post project completion, and for the following three years thereafter. The Company then calculated the difference between the pre-project average tree-related CI's and the post-project average tree-related CI's by calculating the percent improvement for each individual circuit in the annual work plan, and by calculating a running average percent improvement for all circuits completed under the EHTM Program.

Table 1 below is a summary of the reliability results for the EHTM Program.

Table 1 – EHTM Program Reliability Results

EHTM Project Year	Average Annual CI Pre-Project	CI 1st Year Post-Project	% Improved	CI 2nd Year Post-Project	% Improved	CI 3rd Year Post-Project	% Improved
2008	22,127	12,513	43%	7,477	66%	9,213	58%
2009	32,092	6,548	80%	9,013	72%	15,972	50%
2010	50,145	6,731	87%	13,032	74%	12,247	76%
2011	1,133	186	84%	425	62%	202	82%
2012	8,601	2,972	65%	522	94%	1,859	78%
2013	15,109	3,816	75%	4,647	69%	5,159	66%
2014	13,048	628	95%	9,788	25%	2,807	79%
2015	10,902	12,798	-17%	15,745	-44%	-	-
2016	4,060	775	81%	-	-	-	-

* Negative numbers represent an increase from established baseline value.

Since the beginning of the EHTM Program in FY 2008, there has been an average tree-related CI improvement of 70% in the first year, 58% in the second year, and 62% in the third year following project completion. The full data set showing all calculations and results by circuit for the entire EHTM Program is included as <u>Attachment Rec 11-1</u> to this filing.

While the primary goal of the EHTM Program is to improve reliability, the Cycle Pruning Program provides benefits to the Company and its customers by maintaining and improving both public and worker safety. Furthermore, the Cycle Pruning Program increases the efficiency of the Company's line maintenance crews, and increases the efficiency and accuracy of the Company's line inspectors. However, since the intermittent contact of branches against overhead distribution wires due to vegetation growth does not specifically cause service interruptions, the clearance of those branches through the Cycle Pruning Program will not necessarily show a significant and consistent improvement in reliability.

Table 2 below is a summary of the reliability results for the Cycle Pruning Program.

Table 2 – Cycle Pruning Program Reliability Results

Cycle Prune Project Year	Average Annual CI Pre-Project	CI 1st Year Post-Project	% Improved	CI 2nd Year Post-Project	% Improved	CI 3rd Year Post-Project	% Improved
2007	55,494	60,868	-10%	48,121	13%	39,215	29%
2008	47,466	30,333	36%	28,356	40%	82,400	-74%
2009	50,362	38,327	24%	56,979	-13%	48,734	3%
2010	58,009	53,466	8%	48,340	17%	23,332	65%
2011	77,634	26,171	66%	33,166	57%	16,592	79%
2012	30,322	21,523	29%	15,864	48%	19,058	37%
2013	18,923	12,441	34%	16,180	15%	29,171	-54%
2014	26,964	22,939	15%	37,294	-38%	30,131	-12%
2015	23,451	31,726	-35%	20,122	14%	-	-
2016	15,606	27,162	-74%	-	-	-	-

* Negative numbers represent an increase from established baseline value.

While the results for the Cycle Pruning Program are less consistent than the reliability results from the EHTM Program, this study demonstrates that the Company's Cycle Pruning Program creates, on average, a 20% improvement in reliability in the first year, 19% in the second year, and 25% in the third year following project completion. These modest improvements in reliability are attributable to the fact that the Cycle Pruning Program is designed to maintain safe and reliable electric service, as opposed to the EHTM Program which is designed to improve reliability. The full data set showing all calculations and results by circuit for the Cycle Pruning Program is included as Attachment Rec 11-1 to this filing.

In an effort to normalize the data used to show the benefits of the EHTM Program, the Company compared state-wide tree-related CI's for the same fiscal years as shown previously in Table 1. In Table 3 below, the % Improvement column on the far right clearly shows that the EHTM Program has provided statistically significant reliability benefits.

Table 3 – EHTM Program Benefits Compared to Statewide Performance

	Average Annual CI Pre-Project	Average Annual CI - Post- Project (all full years available)	% Improvement
FY 2008 (3 years of data post-project)			
EHTM Feeders	22,127	9,734	56%
All RI Feeders (State-wide)	103,442	87,826	15%
FY 2009 (3 years of data post-project)			
EHTM Feeders	32,092	10,511	67%
All RI Feeders (State-wide)	117,673	94,133	20%
FY 2010 (3 years of data post-project)			
EHTM Feeders	50,145	10,670	79%
All RI Feeders (State-wide)	99,345	98,612	1%
FY 2011 (3 years of data post-project)			
EHTM Feeders	1,133	271	76%
All RI Feeders (State-wide)	93,243	86,832	7%
FY 2012 (3 years of data post-project)			
EHTM Feeders	8,601	1,784	79%
All RI Feeders (State-wide)	87,826	77,696	12%
FY 2013 (3 year of data post-project)			
EHTM Feeders	15,109	4,541	70%
All RI Feeders (State-wide)	94,133	84,265	10%
FY 2014 (3 year of data post-project)			
EHTM Feeders	13,048	4,408	66%
All RI Feeders (State-wide)	98,612	98,954	0%
FY 2015 (2 years of data post-project)			
EHTM Feeders	10,902	14,272	-31%
All RI Feeders (State-wide)	86,832	112,563	-30%
FY 2016 (1 year of data post-project)			
EHTM Feeders	4,060	775	81%
All RI Feeders (State-wide)	77,696	105,847	-36%

Section 2 – Damage Restoration Cost-Benefit for the EHTM Program

The Company does not have the ability to track actual repair costs by event, so estimates were created to perform analysis of the damage restoration cost benefit. The Company generated repair cost estimates for the following types of repairs: replacing a blown fuse, replacing a broken cross-arm, and replacing a broken pole. The Company then reviewed actual interruption records for the EHTM Program feeders for three years pre-project and for three years post-project. The Company estimated the required capital and expense repair work costs using the event description record and information regarding any other work required, such as removing a tree or trimming vines. Table 4 below includes the results of the calculation of repair costs on the EHTM Program feeders for both pre-project and post-project periods. In summary, there is a 5% average reduction in annual repair costs on a circuit where the EHTM Program has been employed.

Table 4 - Damage Restoration Cost Reductions

Feeder	Annual AVG Repair Costs Pre-Project	Annual AVG Repair Costs Post-Project (3 Years Max.)	% Improvement
49_53_13F2	$ 566	$ 229	60%
49_53_34F2	$ 1,877	$ 601	68%
49_53_51F1	$ 1,938	$ 722	63%
49_53_69F1	$ 203	$ 655	-223%
49_56_33F4	$ 745	$ 1,137	-53%
49_56_54F1	$ 6,040	$ 5,701	6%
49_56_63F6	$ 916	$ 1,042	-14%
49_53_102W51	$ 206	$ -	100%
49_53_112W42	$ 677	$ 419	38%
49_53_2291	$ -	$ -	-
49_53_23F1	$ 1,289	$ 341	74%
49_53_38F1	$ 2,014	$ 2,176	-8%
49_53_5F4	$ 1,166	$ 206	82%
49_56_22F4	$ 719	$ 588	18%
49_56_30F1	$ 3,959	$ 772	80%
49_56_52F3	$ 2,069	$ 660	68%
49_53_108W62	$ 41	$ -	100%
49_53_20F2	$ 63	$ -	100%
49_53_38F5	$ 1,504	$ 2,449	-63%
49_53_5F2	$ 1,202	$ 1,330	-11%
49_53_5F3	$ 538	$ 951	-77%
49_53_7F1	$ 41	$ 332	-719%
49_56_16F1	$ 1,095	$ 1,845	-69%
49_56_17F2	$ 462	$ 1,817	-293%
49_56_42F1	$ 1,617	$ 1,601	1%
49_56_43F1	$ 3,210	$ 5,764	-80%
49_56_46F2	$ 3,343	$ 3,141	6%
49_56_59F4	$ 462	$ 319	31%
49_56_72F3	$ 978	$ 837	14%
49_53_38F5	$ 1,129	$ 3,970	-252%
49_53_112W44	$ 6,381	$ 4,561	29%
49_53_126W41	$ 3,572	$ 4,886	-37%

49_53_15F1	$ 1,736	$ 547	68%
49_53_34F3	$ 8,601	$ 9,928	-15%
49_56_43F1	$ 11,830	$ 8,906	25%
49_56_59F4	$ 2,785	$ 2,093	25%
49_53_107W83	$ 99	$ 656	-563%
49_53_126W41	$ 5,213	$ 5,863	-12%
49_53_15F1	$ 5,805	$ 2,530	56%
49_53_18F6	$ 6,095	$ 2,639	57%
49_53_27F1	$ 1,669	$ 1,688	-1%
49_53_38F4	$ 3,192	$ 2,262	29%
49_53_4F1	$ 2,983	$ 1,607	46%
49_53_4F2	$ 6,061	$ 4,666	23%
49_56_14F1	$ 2,271	$ 1,630	28%
49_56_22F2	$ 3,261	$ 570	83%
49_56_57J2	$ 175	$ 341	-95%
49_56_57J5	$ 364	$ 351	4%
49_56_68F3	$ 8,453	$ 8,705	-3%
49_56_88F5	$ 7,802	$ 11,634	-49%
49_53_112W42	$ 4,250	$ 2,212	48%
49_53_112W41	$ 1,231	$ 785	36%
49_53_18F7	$ 2,031	$ 732	64%
49_56_33F3	$ 10,254	$ 9,544	7%
49_56_33F1	$ 4,860	$ 3,033	38%
49_56_33F2	$ 3,285	$ 844	74%
49_56_38K23	$ -	$ -	-
49_53_21F1	$ 3,699	$ 4,403	-19%
49_53_21F2	$ 4,327	$ 2,310	47%
49_53_21F4	$ 1,260	$ 2,698	-114%
49_53_34F2	$ 16,866	$ 15,762	7%
49_53_38F1	$ 11,533	$ 16,554	-44%
49_56_54F1	$ 18,195	$ 26,480	-46%
49_56_63F3	$ 5,167	$ 5,934	-15%
49_56_63F6	$ 9,486	$ 12,526	-32%
49_56_85T3	$ 10,222	$ 7,737	24%
49_56_40F1	$ 122	$ -	100%
49_56_41F1	$ 11,113	$ 6,169	44%
49_56_88F3	$ 8,613	$ 7,294	15%
49_56_37W41	$ 1,689	$ 3,031	-79%
49_56_37W42	$ 969	$ -	100%
49_56_37W43	$ 512	$ 768	-50%
Totals	**$ 258,103**	**$ 244,481**	**5%**

The Company also calculated the total cost benefit for the EHTM Program by program year. This calculation is made by dividing the total program cost, in this case the actual annual spend for the EHTM Program, by the CI benefit or change. Table 5 below shows the calculation and the benefit as a rolling index over the three years post-project completion.

Table 5 – EHTM Program Cost-Benefit ($/ΔCI)

		Post-Project Year 1		Post-Project Year 2		Post-Project Year 3	
Project Year	**EHTM Cost**	**Δ CI**	**$ / Δ CI**	**Average Δ CI**	**$ / Δ CI**	**Average Δ CI**	**$ / Δ CI**
2008	$579,857	9,614	$60	12,132	$48	12,393	$47
2009	$497,187	25,544	$19	24,311	$20	21,581	$23
2010	$486,681	43,387	$11	40,264	$12	39,476	$12
2011	$69,256	947	$73	828	$84	931	$74
2012	$560,213	5,630	$98	6,854	$80	6,817	$81
2013	$752,577	11,293	$67	11,185	$67	10,568	$71
2014	$474,608	12,420	$42	7,840	$61	8,640	$55
2015	$763,559	(1,896)	$(403)	(3,370)	$(227)	-	-
2016	$646,253	3,285	$197	-	-	-	-
Totals	**$4,830,191**	**110,224**	**$44**	**100,044**	**$42**	**100,406**	**$34**

In summary, from FY 2008 through FY 2016, the Company spent $4.8 million on the EHTM Program. This resulted in a reduction of 110,224 CI's following the first project year, resulting in a unit cost reduction of $44 per CI. Using two years of data, resulted in a reduction of 100,044 CI's, resulting in a unit cost reduction of $42 per CI. Using three years of data, resulted in a reduction of 100,406 CI's, resulting in a unit cost reduction of $34 per CI.

Using the same method as the EHTM Program, Table 6 below shows the $/ΔCI for the Cycle Pruning Program.

Table 6 – Cycle Pruning Program Cost-Benefit ($/ΔCI)

		Post-Project Year 1		Post-Project Year 2		Post-Project Year 3	
Project Year	**Cycle Prune Cost**	**Δ CI**	**$/ Δ CI**	**Average Δ CI**	**$/ Δ CI**	**Average Δ CI**	**$/ Δ CI**
2009	$5,144,193	12,035	$427	2,709	$1,899	2,348	$2,191
2010	$4,365,639	4,543	$961	7,106	$614	16,297	$268
2011	$3,956,357	51,463	$77	47,966	$82	52,324	$76
2012	$3,919,065	8,799	$445	11,629	$337	11,507	$341
2013	$4,764,000	6,482	$735	4,612	$1,033	(341)	$(13,958)
2014	$5,180,000	4,025	$1,287	(3,152)	$(1,643)	(3,157)	$(1,641)
2015	$4,475,000	(8,275)	$(541)	(2,473)	$(1810)	-	$-
2016	$5,414,000	(11,556)	$(469)	-	$-	-	$-
Totals	**$37,218,254**	**67,517**	**$551**	**68,397**	**$465**	**78,978**	**$346**

In summary, from FY 2009 through FY 2015, the Company spent $37.2 million on cycle pruning. This resulted in a reduction of 67,517 CI's following the first project year, resulting in a unit cost reduction of $551 per CI. Using two years of data, resulted in a reduction of 68,397

CI's, resulting in a unit cost reduction of $465 per CI. Using three years of data, resulted in a reduction of 78,978 CI's, resulting in a unit cost reduction of $346 per CI. Again, an established Cycle Pruning Program is mainly designed to maintain reliability levels with the potential to only produce modest improvements in CI, all while providing very important public and worker safety benefits.

Recommendation 12

Metal-Clad Replacement Cost-Benefit Analysis

Recommendation 12: Metal-Clad Replacement Cost-Benefit Analysis

National Grid shall continue to submit its Metal-Clad Switchgear replacement program cost-benefit analysis to the Division prior to submitting the Company's FY2019 ISR Plan Proposal, but in any event no later than August 31, 2017.

Metal-Clad Replacement Cost-Benefit Analysis

Currently there is no new metal-clad switchgear replacement projects proposed within the five year spending plan.

Recommendation 13

Verizon Joint Ownership Agreement

Recommendation 13: Verizon Joint Ownership Agreement

National Grid shall continue to provide quarterly confidential reports to the Division concerning the progress of negotiations with Verizon on a new Joint Ownership Agreement.

Verizon Joint Ownership Agreement

A new Joint Ownership Agreement between the Company and Verizon was submitted to the Division on 08/04/2017. A copy of this filing is provided in Attachment Rec 13-1.

NERI 12-3

Request:

Subject: Book 1 – Horan

Reference p. 23, ll. 7-9, stating that "The Company is proposing a return on equity of 10.1 percent at the lower end of the range of the market cost of equity determined by Mr. Hevert using his methodological approach, as he discusses in detail in his testimony." Is the Company's proposed ROE of 10.1% higher or lower than the Company's estimate of the IRR that it believes is adequate for projects developed through the REG program? If higher, why is NGrid entitled to a higher return from its customers than is needed to spur private investment?

Response:

The Company has not performed studies to determine the appropriate internal rate of return that would be appropriate for projects developed through the Renewable Energy Growth Program.

Prepared by or under the supervision of: Joshua Nowak

NERI 12-4

Request:

Subject: Book 1 – Horan

How does utility ownership of solar and storage projects comport with the restructuring required per RIGL 39-1-27?

Response:

As part of restructuring, R.I. Gen. Laws § 39-1-27 required utilities to file plans for transferring ownership of generation, transmission, and distribution facilities into separate affiliates, and to provide nondiscriminatory access to transmission and distribution facilities to wholesale and retail customers and to nonregulated power producers. In addition, subsection (d) prohibits electric distribution companies in Rhode Island from owning, operating or controlling generation:

> Following the complete implementation of the restructuring plans, electric distribution companies shall be prohibited from selling electricity at retail and from owning, operating or controlling generating facilities, although such facilities may be owned by affiliates of electric distribution companies. R.I. Gen. Laws § 39-1-27(d).

R.I. Gen. Laws § 39-26-6(g), however, establishes a carve-out for utility ownership of up to 15MW of "renewable generation demonstration projects" on a pilot basis, with the pertinent language stating:

> Consistent with the public policy objective of developing renewable generation as an option in Rhode Island, and subject to the review and approval of the commission, the electric distribution company is authorized to propose and implement pilot programs to own and operate no more than fifteen megawatts (15MW) of renewable-generation demonstration projects in Rhode Island and may include the costs and benefits in rates to distribution customers.

The Company's Solar Program, as described in Schedule PST-1, Chapter 8 – Income Eligible, Section 4 (Bates Pages 140-150 of PST Book 1), fits squarely within the aforementioned exception to restructuring, in that the Company is proposing to invest in up to 3.75 MW of solar facilities. The Company intends to design its Solar Program to benefit customers of non-profit affordable housing projects in accordance with the requirements of R.I. Gen. Laws § 39-26-6(g).

With respect to energy storage facilities, it should be noted that the Rhode Island Renewable Energy Standard, R.I. Gen. Laws § 39-26-2, defines a "generation unit" as "a facility that *converts* a fuel or an energy resource *into* electrical energy" (emphasis added). Storage technology does not serve this function. Storage technology is designed to *absorb* energy; hold it for a period of time; and thereafter dispatch the energy to the grid. Therefore, energy storage does not constitute a "generation unit" under Rhode Island law, and is not subject to the restructuring requirements.