2020 SYSTEM RELIABILITY PROCUREMENT REPORT

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2020 SYSTEM RELIABILITY PROCUREMENT PLAN REPORT

1. Executive Summary

The purpose of System Reliability Procurement (SRP) is to identify targeted alternative solutions, through customer-side and grid-side opportunities, for the electric distribution system that are cost-effective, reliable, prudent and environmentally responsible and provide the path to lower supply and delivery costs to customers in Rhode Island.

The role of National Grid[1] with respect to SRP is to identify potential Non-Wires Alternative (NWA) opportunities and to source viable solutions that address system needs and reduce, avoid, or defer transmission and distribution (T&D) wires investments.

The Company requests approval from the Public Utilities Commission (PUC) for the proposals as stated in the 2020 SRP Report, which are summarized in the table below. The table in Section 4 contains further detail to the initiatives and proposals, their cost recovery mechanisms (CRM), and their projected future costs.

Table 1: Summary of 2020 SRP Funding Request and Proposals

SRP Section	SRP Proposal	CRM	Cost
5.3	SRP Incentive Mechanism, 2018 Action-Based Earnings	EE Charge	$11,865
11	SRP Market Engagement	EE Charge	$69,370
		Total	**$81,235**

The commitments that do not require SRP funding but which are included in the 2020 SRP Report are summarized in the following table.

Table 2: Summary of 2020 SRP Report Commitments

SRP Section	SRP Commitment
1	The Company commits to performing background research on NPAs and exploring how NPAs align with Company policy and the SRP Standards for the next update in the Three-Year Plan review. The Company commits to engaging with stakeholders to discuss and understand opportunities and challenges regarding NPAs.

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

SRP Section	SRP Commitment
8	The Company plans to continue analyzing its current NWA screening and development processes to determine how NWAs might be best considered as both complete and partial solutions.
9.5	The Company commits to the following actions with the intent of increasing the viability of the South County East NWA Projects: 1. Analyze whether there are additional benefit streams available that can be combined with NWAs to create more cost-effective solutions. 2. Refine the parameters of the need to capture additional benefits, if applicable. 3. Assess the option of a Company-sourced proposal, where the Company formulates a proposal with specific parameters to be fulfilled by the market, which would be used to compare against third party solutions.
9.5	The Company commits to investigating viable alternate solution pathways for the Narragansett 42F1 and South Kingstown NWA opportunities.
10.2	Begin coordination work with the Company’s proposed Grid Modernization Plan regarding inclusion of hourly (8,760 hours) data in addition to peak load data once the Grid Modernization Plan with this update is approved for funding.
12	The Company recognizes that improved synchronization between SRP and Power Sector Transformation (PST), the Energy Efficiency Program Plan (EE Plan), the Infrastructure, Safety and Reliability Plan, the Grid Modernization Plan (GMP), and the Advanced Metering Functionality (AMF) Business Case is necessary and intends to improve coordination between these filings.
12	Therefore, the Company commits to continued stakeholder engagement and continued participation in enhanced discussions regarding SRP, NWA, and related policy and programs with stakeholders.
12	The Company also commits to continue its efforts to actively avoid double-counting shareholder incentives in SRP programs and projects.
12.1	The Company intends to implement robust stakeholder engagement and discussion on the electric forecasting process.
12.1	The Company will commit to development and implementation of a data governance plan in coordination with the work on the AMF and GMP filings, and will continue stakeholder engagement and discussion.

SRP Section	SRP Commitment
12.1	The Company commits to stakeholder engagement and discussion regarding locational incentives through in Rhode Island by July 31, 2020 through the SRP TWG meetings and other relevant sessions, and to determine whether the current methodology should be modified.

Sections 1 through 3 are informative sections that outline the background of SRP, the Company's overall proposal, and the regulatory basis for SRP.

Section 4 details the funding request and associated customer charge for this SRP Report. In this section, the Company requests approval on the proposed funding request for the projects and initiatives included in this SRP Report. Please note that the CRM for SRP is the SRP charge, or the "Proposed System Reliability Factor per kWh" value in Table S-1, which folds into the energy efficiency (EE) charge on customers' bills.

Section 5 describes the incentive mechanism for SRP. The incentive mechanism contains savings-based incentives and earned incentives to further advance achievement of Least-Cost Procurement (LCP) goals. In this section, the Company requests approval on the proposed earnings for the action-based incentive items achieved in calendar year 2018.

Sections 6 is an informative section that details the Company's alignment with Docket 4600 principles and goals.

Section 7 is an informative section that holistically details the load growth forecast of the electric distribution system in Rhode Island in coordination with NWA planning and opportunities.

Section 8 is an informative section that details how NWAs are part of the electric distribution planning process. This section also identifies area studies relevant to NWA opportunities and analyses.

Section 9 details the South County East NWA opportunities. This section provides information from the South County East Area Study which details the potential for NWA opportunities in the Towns of Narragansett and South Kingstown. In this section, the Company requests approval on the proposed South County East NWA opportunities and their respective funding requests.

Section 10 details the Rhode Island System Data Portal (Portal) and associated resources and its current implementation status. The Company commits to coordination work regarding hourly data for further Portal enhancement in this section.

Section 11 describes market engagement efforts the Company performs with respect to SRP. The Company currently implements the 2019 SRP Marketing and Engagement Plan, as detailed in this section and included as an appendix. In this section, the Company requests approval on the proposed 2020 SRP Outreach and Engagement Plan and its respective funding request.

Section 12 is an informative section that describes coordination with Power Sector Transformation and the Energy Efficiency Program, Grid Modernization and Advanced Metering Functionality, and Infrastructure, Safety and Reliability plans.

Section 13 contains the miscellaneous provisions and signature pages of the settling parties for this 2020 SRP Report.

A new potential solution pathway in system planning is Non-Pipeline Alternatives (NPAs). The Company commits to performing background research on NPAs and exploring how NPAs align with Company policy and the SRP Standards for the next update in the Three-Year Plan review. The Company commits to engaging with stakeholders to discuss and understand opportunities and challenges regarding NPAs.

The proposals and information the Company presents in this SRP Report advance Power Sector Transformation goals, align with Docket 4600 principles, are coordinated with the Company's other programs and filings, and adhere to the Least-Cost Procurement law.

2. Introduction

The Company is pleased to submit this annual 2020 System Reliability Procurement Report (SRP Report) to the PUC. The SRP Report has been developed by National Grid through an iterative process with the SRP Technical Working Group (the SRP TWG).[2][3]

This Plan is being jointly submitted as a Stipulation and Settlement (Settlement) between the Acadia Center, Division of Public Utilities and Carriers (Division), the Energy Efficiency and Resource Management Council (EERMC), Green Energy Consumers Alliance[4], the Office of Energy Resources (OER), The Energy Council of Rhode Island (TEC-RI), and National Grid (together, the Parties). This Plan addresses a range of topics discussed by members of the SRP TWG regarding the Company's SRP Report for calendar year 2020.

National Grid respectfully seeks approval of this 2020 SRP Report and its integral proposals in accordance with the guidelines set forth in Section 2 of the SRP Standards.

[2] Members of the SRP TWG presently include the Company, the Division, OER, TEC-RI, Green Energy Consumers Alliance, Acadia Center, several EERMC members, and representatives from the EERMC's Consulting Team.

[3] "The Collaborative." *RI Energy Efficiency & Resource Management Council*, RI Energy Efficiency & Resource Management Council, https://rieermc.ri.gov/thecollaborative/.

[4] Formerly People's Power & Light.

3. Regulatory Basis for System Reliability Procurement

This SRP Report is submitted in accordance with the Least-Cost Procurement law, R.I. Gen. Laws § 39-1-27.7, the basis for which is the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006[5] (the 2006 Act) and as amended in May 2010. The 2006 Act provides the statutory framework for least-cost procurement, including system reliability in the State of Rhode Island. The 2006 Act provides a unique opportunity for Rhode Island to identify and procure cost-effective customer-side and distributed resources with a focus on alternative solutions to the traditional supply and infrastructure options. These alternative solutions may deliver savings to customers by deferring or removing the need for distribution system investment and improving overall system reliability over time.

This SRP Report is also submitted in accordance with the Rhode Island PUC's revised "System Reliability Procurement Standards," which the PUC approved in Docket No. 4684 (SRP Standards).[6] The Least-Cost Procurement law, R.I. Gen. Laws § 39-1-27.7, requires standards and guidelines for system reliability. On September 8, 2018 in Docket 4684, the PUC unanimously approved the revised standards for system reliability, finding that the standards were consistent with the policies and provisions of R.I. Gen. Laws 39-1-27.7.1(e)(4),(f) and R.I. Gen. Laws § 39-1-27.7.3.

> ***§ 39-1-27.7. System reliability and least-cost procurement.*** *– Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.*[7]

The Least-Cost Procurement law further states that SRP resources are intended to include, but are not limited to, the following:

(i) *Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title;*

[5] "The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006." *State of Rhode Island General Assembly*, 25 Apr. 2006, http://www.ripuc.org/eventsactions/docket/3759-RIAct.pdf.

[6] "Least Cost Procurement Standards." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 8 Sep. 2018, http://www.ripuc.org/eventsactions/docket/4684-LCP-Standards-FINAL.pdf.

[7] "Title 39 Public Utilities and Carriers." *State of Rhode Island General Laws*, State of Rhode Island General Assembly, http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.HTM.

(ii) *Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost-effective, with measurable, net system benefits;*

(iii) *Demand response, including, but not limited to, distributed generation, back-up generation and on-demand usage reduction, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;*

SRP resources include, in part, NWA initiatives. Section 2.3.A of the SRP Standards requires that the Company identify T&D projects that meet certain screening criteria for potential NWAs that reduce, avoid, or defer T&D wires investments.

The definition and requirements of NWAs are as follows:

NWA Definition:	Non-Wires Alternatives is the inclusive term for any targeted electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment".
NWA Requirements:	These NWA investments are required to be cost-effective and are required to meet the specified electrical grid need.

Cost-effectiveness involves comparison of the total benefits, of applicable benefit factors from the Rhode Island Benefit-Cost Model Test (RI Test), to the total cost of the proposed NWA solution, as assessed in benefit-cost analysis (BCA). The NWA investment is considered cost-effective if the benefit-cost ratio (BCR) for the NWA is greater than 1.0. The BCA methodology for NWA proposals is consistent with the language in the SRP Standards section 2.3.F and Docket 4600 framework.

An NWA can include any action, strategy, program, or technology that meets this definition and these requirements. The Company is currently engaged in ongoing discussions with stakeholders about non-clean energy and how it is considered in NWA solutions, proposals, and investment decisions.

Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs) and distributed generation (DG). NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

The maximum amount payable for NWA resources will be an annualized amount of the Approximate Value for the NWA opportunity. This Approximate Value is a net present value (NPV) calculated from 60% of the deferral value of the otherwise needed localized wires investment option, which by default are location-based avoided costs. The 60% rate is the application of the Rhode Island Locational Incentive, as described in the 2019 SRP Report, to provide greater value to Rhode Island customers. The Approximate Value is stated in NWA requests for proposals (RFPs) to help inform third-party solution providers whether their NWA solution bid is cost-effective for the need. Any contracts to procure NWAs would have to be approved by the PUC, as required for all non-tariff contracts.

Section 2.5.A of the SRP Standards further require the Company to submit, by November 1 of each year, an annual SRP Report that includes, among other information, a summary of where NWAs were considered, identification of projects where NWAs were selected as a preferred solution, an implementation and funding plan for selected NWA projects, recommendations for demonstrating distribution or transmission projects for which the Company will use selected NWA reliability and capacity strategies, and the status of any previously approved NWA projects. For additional discussion on the criteria for NWA analysis, please see Section 8.

In addition to NWA opportunities, SRP resources can also include other efforts that adhere to the Least-Cost Procurement goals; that these resources be *complementary but distinct activities that have a common purpose of meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible*.

4. Funding Request for System Reliability Procurement

The Company proposes to fund the projects and initiatives included in this SRP Report through the EE charge on customers' bills, as has been done historically. The tables below illustrate the breakdown of the Company's funding request and the proposed customer charge associated with SRP for 2020.

All funding requests made in this Report are factored into the SRP cost recovery mechanism, which is the SRP charge, or the "Proposed System Reliability Factor per kWh" value in Table S-1, which folds into the EE charge on customers' bills. The proposals and funding requests in this Report are not complemented by or funded through other Company programs or plans.

The Company estimates that the incremental costs stated in the table below will be required in 2020 to implement the projects and initiatives detailed in this Report. Please note that the costs stated for calendar years following 2020 are informative to detail potential future costs. These potential future costs could change in subsequent annual SRP Reports, based on the finalized proposal made in a specific year.

The Company requests approval for recovery of these proposed funds.

Table 3: Summary of 2020 SRP Funding Request

SRP Section	SRP Initiative/Proposal	CRM	CY 2020	CY 2021	CY 2022
5.3	SRP Incentive Mechanism, 2018 Action-Based Earnings	EE Charge	$11,865	$0	$0
5.4	SRP Incentive Mechanism, 2020 Savings-Based Earnings	EE Charge	$0	unk.	unk.
9.2	Narragansett 42F1 NWA Project	EE Charge	$0	unk.	unk.
9.3	Narragansett 17F2 NWA Project	EE Charge	$0	N/A	N/A
9.4	South Kingstown NWA Project	EE Charge	$0	unk.	unk.
10	Rhode Island System Data Portal	EE Charge	$0	unk.	unk.
11	SRP Market Engagement	EE Charge	$69,370	$8,000	$8,000
		Total	**$81,235**	**$8,000**	**$8,000**

Please note that the cells that state "unk." in Table 3 indicate unknowns because SRP plan development during future years will determine applicable funding requests for those items.

Please reference Section 9.3 for why funding requests are not applicable in future years for the Narragansett 17F2 NWA Project line item.

Table S-1: RI SRP 2020 Funding Sources

Table S-1
National Grid
System Reliability Procurement
Funding Sources
$(000)

		2020
(1)	**2020 SRP Budget:**	**$81.2**
(2)	**Projected Year-End Fund Balance and Interest:**	**-$1,001.3**
(3)	**Customer Funding Required:**	**$1,082.6**
(4)	**Forecasted kWh Sales:**	**7,113,299,305**
(5)	**Proposed System Reliability Factor per kWh:**	**$0.00015**
(6)	**Energy Efficiency Program charge per kWh, excluding uncollectible recovery:**	**$0.01324**
(7)	**Total Proposed Energy Efficiency Charge per kWh, excluding uncollectible recovery:**	**$0.01339**
(8)	**Energy Efficiency Program Charge per kWh, including uncollectible recovery:**	**$0.01356**

Notes
(1) The projected SRP Budget includes only additional funds for SRP. It does not include costs associated with focused energy efficiency.
(2) "Total Proposed Energy Efficiency Charge per kWh, excluding uncollectible recovery" is the sum of the "Proposed System Reliability Factor per kWh" and "Energy Efficiency Program charge per kWh, excluding uncollectible recovery" lines.
(3) All dollar amounts shown are in $current year.
(4) Table lines (6), (7), and (8) are included here for reference from Table E-1 of the Energy Efficiency Program Plan.

Please note that Item 2 in Table S-1, the Projected Year-End Fund Balance and Interest, is significantly negative compared to prior years because of the following reason:

- An error was identified in the SRP Tracking spreadsheet, which resulted in the SRP ending balance exceeding the revenue requirements needed to fund the program for 2016, 2017, and 2018. The error in the "Proposed System Reliability Factor per kWh" value over-apportioned funds to SRP from EE. Despite this error, collections from customers for the overall EE charge, which includes SRP, were correct for those years.
- Once identified, an adjustment was made to reapportion revenue from SRP back to EE. This adjustment was based on the filed "System Reliability Factor per kWh" for 2016

through 2018. The correction was accounted for in the January 2019 activity in the SRP Tracking worksheet. This adjustment allows the company to collect the minimal amount of funding needed to administer EE programs in 2019.

- The 2019 "Proposed System Reliability Factor per kWh" and January 2019 adjustment will cause SRP to become underfunded for 2019, resulting in an increase in the "Proposed System Reliability Factor per kWh" in 2020.
- We expect the 2020 ending balance for SRP to be in line with revenue requirements for the period.

5. SRP Incentive Mechanism

This section details the SRP Incentive Mechanism and involved action-based, savings-based, and earned incentives to advance LCP goals.

The Company and the Parties have agreed on savings-based metrics for the Company to earn incentives on work completed through SRP in 2020.

5.1 SRP Action-Based Incentives for 2020

The Company is not proposing any action-based incentives for 2020.

5.2 Earned Incentives from 2019 SRP Report

There were no approved action-based incentive items from the 2019 SRP Report.

5.3 Earned Incentives from 2018 SRP Report

The Company proposed the following actions and associated percentages of the 2018 SRP budget that can be earned as described in the 2018 SRP Report.

Table 4: Summary of 2018 SRP Report Action-Based Incentives

Section	Action	Date	% of 2018 SRP Budget	Action Complete?	% of 2018 SRP Budget	Calculated Earnings
Rhode Island System Data Portal & Heat Map Resources	Complete an Initial Version of the Portal	June 30, 2018	1%	Yes	1%	$2,373
Rhode Island System Data Portal & Heat Map Resources	Complete DG-Focused Map	September 30, 2018	1%	Yes	1%	$2,373
Rhode Island System Data Portal & Heat Map Resources	Complete a Stakeholder Review Process of Location-Based Avoided Costs	August 31, 2018	1%	No	1%	N/A
Market Engagement with NWAs	Develop and Deploy an Initial Marketing & Engagement Plan	March 31, 2018	1%	Yes	1%	$2,373
Rhode Island System Data Portal & Heat Map Resources	Issue at least two new RFPs for NWA Resources	December 31, 2018	2%	Yes	2%	$4,746
					Total Earn to Date	**$11,865**

Regarding the potential incentive earnings to date, the status and calculated earnings are detailed as follows:

- The completed action-based incentive items for calendar year 2018 are:
    - The initial version of the Portal was completed by June 30, 2018.

  - The initial version of the Hosting Capacity (DG-focused) map was completed by September 30, 2018.
  - An initial version of the Marketing & Engagement Plan was developed and deployed by March 31, 2018.
  - The two new RFPs for NWA resources were issued by December 31, 2018.

- The stakeholder review process of location-based avoided costs was not completed by the assigned date. Please see Section 12.1 for further information on the Company's intent for continued stakeholder engagement with regard to the review process of location-based avoided costs.

- The 2018 SRP budget spend for calendar year 2018 is $237,306.

- The total achieved percentage of 2018 SRP budget spend is 5%.

- The total potential incentive earnings are calculated from the total achieved percentage multiplied by the 2018 SRP budget spend for calendar year 2018.

- Therefore, the total potential incentive earnings to date is calculated to be $11,865.

5.4 SRP Savings-Based Incentives

The Company will be able to earn savings-based incentives for DERs that are installed as a result of NWA RFPs. The Company will be obligated to demonstrate that DERs were installed as a result of NWA opportunities. This demonstration would require:

1. An affidavit from the DER provider that Company marketing influenced their decision to site, and
2. Confirmation that the DER was installed in the current year of the SRP Report (e.g. calendar year 2020), and
3. Measured output at the feeder during peak hours showing the specific DER's contribution to peak load reduction.

For the Company to earn savings-based incentives on DERs, the DERs must be deemed cost-effective according to the Rhode Island cost-effectiveness framework established in the Commission's Docket 4600 Guidance Document. DERs that are statutory such as net metering and the RE Growth program are assumed to be cost-effective as per the PUC's initial guidance in the Docket 4600 process.

Savings associated with programs for which the Company earns an incentive from other sources (e.g. RE Growth) will not be included in the Company's savings-based incentive calculation.

The savings-based incentive will allow the Company to earn a share of the net benefits of the installed DERs that meet the demonstration criteria described above. Net benefits are defined as the remaining sum left after total costs have been subtracted from the total benefits; net benefits are synonymous with savings in the context of the savings-based incentive. Net benefits will be calculated for DER projects using the Utility Cost Test, which includes only the "power sector" costs and benefits in the Rhode Island cost-effectiveness framework. Participant and societal costs and benefits will not be included for the purpose of determining the shared savings incentive amount. The Utility Cost Test provides the clearest indication of the extent to which DERs reduce costs for all customers. Net benefits will include the location-based avoided distribution costs, if applicable, prepared by the Company, as described above. The location-based avoided distribution costs are the deferral value of the wires investment.

The net benefits of the DERs will be shared by allocating 20% to the Company and 80% to customers, with the share to the Company apportioned annually over the lifetime of the NWA project. The Company earns its apportioned annual share for each year the installed DER meets the three demonstration requirements listed above.

$$Company\ Share = Net\ Benefits \times 20\%$$

$$Apportioned\ Annual\ Company\ Share = \frac{Net\ Benefits \times 20\%}{\#Years\ of\ NWA}$$

$$Customer\ Share = Net\ Benefits \times 80\%$$

The savings-based incentive mechanism would be applied to the net benefits of the NWA project(s) proposed in this SRP Report, as well as any projects installed and marketed as a result of the other SRP initiatives proposed in this report, to the extent they meet the criteria outlined in this section and the projects or initiatives result from RFPs. The savings-based incentive mechanism, assuming the Company meets the threshold requirements for earning the incentive, is illustrated below in the calculation of the savings-based incentive associated with the NWA project(s) proposed in this SRP Report.

There are no applicable NWA projects in this SRP Report for savings-based incentives in calendar year 2020.

5.5 SRP Incentive Mechanism Proposal

The Company requests approval of the proposed earnings for the action-based incentive items achieved in calendar year 2018 as detailed in Section 5.3.

6. Advancing Docket 4600 Principles and Goals

This section illustrates how the 2020 SRP Report advances Docket 4600 principles and goals through the information it provides and proposals the Company puts forth.

The Docket 4600-A Guidance Document directs that "the proposing party must provide accompanying evidence that addresses how the proposal advances, detracts from, or is neutral to each of the stated goals of the electric system."[8]

Along with the quantitative benefits detailed in the Plan, as measured by the RI Test, this SRP Report advances or is neutral to Docket 4600 principles and goals.[9]

To meet this directive, the Company describes in the table below how the SRP Report either advances, detracts, or remains neutral on achieving Docket 4600 goals for the electric system.

Docket 4600 articulates several distinct goals for the electric system in Rhode Island:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);
- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;
- Address the challenge of climate change and other forms of pollution;
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;
- Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;
- Appropriately charge customers for the cost they impose on the grid;
- Appropriately compensate the distribution utility for the services it provides;
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

[8] Approved final clean version of Guidance Document 10/27/17.

[9] PUC Report and Order No. 22851 accepting the Stakeholder Report. Written Order issued July 31, 2017.

Table 5: Docket 4600 Goals for the Electric System

4600 Goals for Electric System	Advances/Detracts/Neutral
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term.	Neutral: This is neutral because, in the 2020 SRP Report, there are no new NWA proposals. The SRP Report provides for safe, clean, and affordable energy to customers through new NWA proposals. These NWA proposals are mandated to be cost-effective, reliable, prudent and environmentally responsible.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.	Neutral: This is neutral because, in the 2020 SRP Report, there are no new NWA proposals. The SRP Report strengthens the RI economy by engaging economic benefits of the RI Test model through NWA project proposals. Additionally, the Company will be engaging with third-party vendors to provide solutions where needed by customers and the electric grid in a cost-effective manner.
Address the challenge of climate change and other forms of pollution.	Advances: This advances Docket 4600 because, in the 2020 SRP Report, the 2020 SRP Report addresses the challenge of climate change and other forms of pollution with the commitment to perform background research on NPAs. SRP adheres to the Least-Cost Procurement law, which mandates, in part, that SRP activities meet electrical energy needs in Rhode Island in a manner that is optimally environmentally responsible. These SRP activities include proposed NWA projects.

4600 Goals for Electric System	Advances/Detracts/Neutral
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits.	Neutral: This is neutral because, in the 2020 SRP Report, there are no new NWA proposals. The SRP Report promotes investment in NWAs, which include such technologies as battery storage, demand response, energy efficiency, and distributed generation.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.	Neutral: This is neutral because, in the 2020 SRP Report, there are no new NWA proposals and the Company has not entered into a contractual agreement with a DER provider through SRP. The SRP Report appropriately compensates DERs when the Company enters an agreement for an NWA project with a third-party DER solution provider. NWA project contracting follows the SRP standards and LCP law, and therefore compensates DERs in a cost-effective manner.
Appropriately charge customers for the cost they impose on the grid.	Neutral: This is neutral because, in the 2020 SRP Report, there are no new NWA proposals. The Company implements locational incentives, as detailed in the 2019 SRP Report, to engage the market and enable NWAs on the electric distribution grid for targeted system needs that customer-side resources impose on the grid. These incentives are reflected in the cost for NWA projects.

4600 Goals for Electric System	Advances/Detracts/Neutral
Appropriately compensate the distribution utility for the services it provides.	Advances: This advances Docket 4600 because, in the 2020 SRP Report, the Company requests approval of the proposed earnings for the action-based incentive items achieved in calendar year 2018. The incentive mechanism contained in this SRP Report compensates the Company for achieving SRP and NWA technologies goals through delivering effective SRP resources and programs to customers.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive.	Advances: This advances Docket 4600 because, in the 2020 SRP Report, the Company commits to several stakeholder and policy objectives such as: continued NWA process analysis to discover any optimizations, coordination work regarding hourly data on the Portal, coordination between Company programs and filings, actively avoid double-counting shareholder incentives in SRP projects, host stakeholder discussions regarding the electric forecasting process, development and implementation of a data access plan, and continued overall stakeholder engagement with SRP.

7. Forecasted Load Growth for NWA Opportunities

This section provides an overview and update on forecasted load growth for locations in Rhode Island that have the potential for NWA opportunities.

The Company's electric distribution system serves close to 500,000 customers in 38 cities and towns in Rhode Island. The residential class accounts for approximately 41% of the Company's total Rhode Island load, the commercial class accounts for approximately 49%, and the industrial class accounts for approximately 10%.

The forecasted load growth rates for cities and towns in Rhode Island are shown in Appendix 2.

Section 7.5 addresses forecasted load growth in the Washington County area, which the South County East NWA opportunities plan to address. As seen in Sections 7.1 through 7.4, the average annual growth rates are projected to be negative over the next 10 years.

The Company has not presently identified other NWA opportunities through the distribution system planning (DSP) process, which is detailed in Section 8.

The Company accounts for energy efficiency, solar photovoltaic (PV) DG, electric vehicles (EV), and demand response (DR) impacts in the Company's electric peak load forecasting as shown in Appendix 2.

7.1 Forecasted Load Growth in Bristol County

The Bristol County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.2% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.0%.

7.2 Forecasted Load Growth in Kent County

The Kent County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.2% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.0%.

7.3 Forecasted Load Growth in Newport County

The Newport County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.2% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.0%.

7.4 Forecasted Load Growth in Providence County

The Providence County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.3% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.0%.

7.5 Forecasted Load Growth in Washington County

The Washington County area annual weather-adjusted summer peak is expected to increase at an average annual growth rate of 0.7% for the next 10 years. This rate is greater than the statewide average annual growth rate of 0.0%.

The towns of Narragansett, Kenyon, and Peace Dale are targeted by the South County East NWAs: Narragansett 42F1 NWA and South Kingstown NWA. The South Kingstown NWA involves parts of the electric distribution grid in the towns of Kenyon and Peace Dale while the Narragansett 42F1 NWA targets the electric distribution grid in the town of Narragansett. Please see Section 9 for further detail on these NWA opportunities.

8. NWAs in System Planning

This section illustrates the NWA planning process for distribution system planning.

The terms "potential NWA opportunity" or "NWA opportunity" refer to a non-wires investment option that has been identified for a specific electric grid need but which has not yet been confirmed as an NWA project for implementation in place of the wires investment option.

An area study is an analysis for a specific, bounded area, typically with respect to a substation and its feeders or a geographical demarcation, that assesses the electric grid characteristics and the health of its equipment.

The initial system assessment consists of a detailed analysis of facilities and system performance within the identified study geographic and electric scope. Initial system assessments are the first step to gather information for area studies and other system evaluations.

Potential NWA opportunity screening and analysis are included as a standard part of the electric distribution system planning process. The Company can potentially own non-wires assets and acquire Company-owned solutions as a result of NWA opportunities.

The Company identifies and screens potential NWA opportunities through the following high-level sequential process:

1. <u>Scoping</u>

   The Distribution Planning and Asset Management (DPAM) team develops a scope for a system need or a scope that details the boundaries and concerns of the area study. Planning criteria, Company standards, and forecasts are inputs to the Scoping stage.

2. <u>Initial System Assessment</u>

   The DPAM team performs an initial system assessment, either as part of an area study or when other targeted asset management and planning projects are initiated.

   To determine whether a potential NWA opportunity is feasible for an electric grid need, the DPAM team screens distribution projects with the criteria listed in Section 2.3.A of the SRP Standards, which are aligned with the Company's internal planning document. Feasibility is based on the screening criteria, which cover technical, economic, and timing factors.

   These NWA screening criteria are applied to an identified electric grid need and resulting potential NWA opportunities are investigated. Partial NWA opportunities are also assessed as an option. Partial NWAs are solutions that address part of a specified system need with the rest of the system need addressed by the wires alternative. A partial NWA effectively reduces the scope of infrastructure projects.

3. Engineering Analysis

An engineering analysis is performed to gather detailed information for comprehensive plan development to solve the system need. This information is also included as part of development of an NWA opportunity and an NWA RFP as required.

Additionally, targeted EE and targeted DR sourced from internal Company programs are assessed at this stage, if timing for the system need allows, to determine whether they are viable components to include as part of an NWA solution.

Grid opportunities that are sufficiently out in the future are periodically re-analyzed to determine whether the system need has changed so that an NWA option is potentially feasible. Timing of re-evaluation is established within the specific area study.

4. Plan Development

Plan development is the stage when wires options and non-wires options are developed. The NWA team develops the NWA RFP, sends the RFP to market, and receives and evaluates NWA bid responses during this stage.

If the DPAM team determines that an NWA opportunity is technically and economically feasible according to the NWA screening criteria, the NWA team then gathers relevant engineering information from the DPAM team and develops an NWA RFP. This engineering information is derived from the engineering analysis. This NWA RFP is then published to the market for third-party solution providers to bid on. The NWA team then evaluates any bids received and selects the most suitable bid for the NWA opportunity. The NWA team proposes the winning NWA solution to the DPAM team as the NWA option for the specified electric grid need.

5. Select Recommended Plan

The DPAM and NWA teams then collaboratively review and compare the wires and non-wires options with respect to project cost and the cost-effectiveness of the options, system reliability, safety, and other factors and finalize the recommended plan. Please refer to Section 3 for explanation on cost-effectiveness and BCA breakdown.

If an NWA option is selected as the solution for the electric grid need, then the NWA solution is proposed through the next SRP Report.

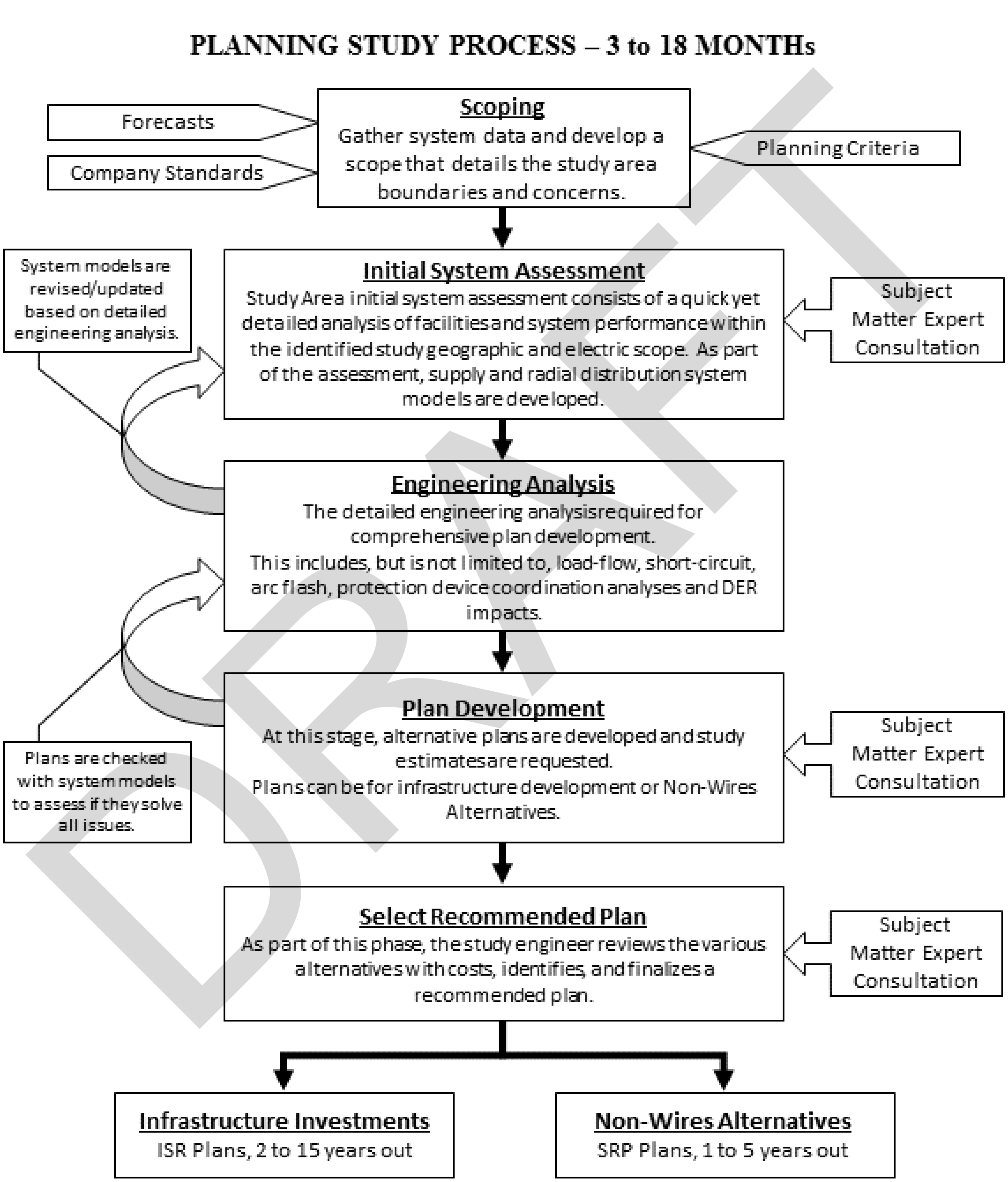
If a wires solution is the best option, and if actual load growth continues at a rate where the wires investment is still needed, then that wires investment is fully developed and incorporated into a future Electric Infrastructure, Safety and Reliability Plan (ISR Plan).

There are projects that have been screened for NWAs that are not included in a given Electric ISR Plan. This is due to a variety of constraints such as need date, coordination with other projects, budget constraints, etc. Instead, these projects may be proposed in a future Electric ISR Plan, if the need still exists, as budgets allow. Therefore, it is possible that there may be projects and budgets related to load growth in the Electric ISR Plan that are not included in the screening conducted for this Report.

Once a wires solution is chosen for a distribution project and is included in an annual Electric ISR Plan filing, it is not screened for NWA feasibility again.

For reference on timing of the NWA review process and possible inclusion in a specific year's Electric ISR Plan please see the figure on the following page, which illustrates the Distribution Planning Study Process. The Distribution Planning Study Process outlines the major steps and study-based inputs in the overall area study process. Please note that capital infrastructure projects that have passed screening for potential NWA opportunities will not be advanced in the Electric ISR Plan unless they have been fully evaluated for NWA. The Company plans to continue analyzing its current NWA screening and development processes to determine how NWAs might be best considered as both complete and partial solutions.

Figure 1: Distribution Planning Study Process Flowchart



8.1 Area Study and NWA Analysis

This section details area studies and distribution projects relevant to NWA opportunities and analysis.

There were 15 discretionary distribution projects initiated between April 1, 2018 and March 31, 2019, and 15 of 15 were determined to be ineligible for NWA consideration. A table detailing the projects reviewed and the reasons for their NWA ineligibility is provided in Appendix 4.

The Company continues NWA screening in its distribution area studies. The following screenings are ongoing:

- Northwest Rhode Island
  Problem identification and solution development: Area study has identified a megawatt hour (MWh) contingency issue for the loss of the Nasonville transformer. Wires and non-wires alternatives are currently being reviewed.

- Central Rhode Island West
  Problem identification and solution development: No opportunities have been identified at this stage of the System Area Study.

- South County West
  Problem identification and solution development: No opportunities have been identified at this stage of the System Area Study.

Additionally, the Company completed a reevaluation of NWA opportunities that were identified in past area studies.

Table 6: Reevaluated NWA Areas

Study Area	Load Relief	Traditional Wires Option
East Bay	12-15 MW	Substation expansion, Feeder installation - Bristol
Providence	3.9 MW	Substation expansion, Feeder installation - Geneva
Providence	2.3 MW	Substation expansion, Feeder installation - Geneva

As part of the Company's reevaluation process, it was determined that the Company should pursue third-party solutions for these previously identified NWA opportunities from the East Bay Study. The Company will move forward with developing an NWA RFP for the East Bay opportunity.

Additionally, the Company has confirmed that the NWA opportunities previously identified in the Providence Area Study are still required. However, the Company will engage the market for potential third-party solutions in later years closer to the in-service need date because the system need is sufficiently out in the future. The Company recognizes that NWA technology costs change over time, and projects that might not have been viable at the time of study might become viable if technology costs decrease over time.

9. South County East NWA Projects

This section details potential NWA opportunities: the Narragansett 42F1 NWA, the Narragansett 17F2 NWA, and the South Kingstown NWA.

The Company is currently pursuing these three potential NWA opportunities that were identified in the South County East Area Study. These NWA opportunities are in Narragansett and South Kingstown.

9.1 Recommendation from the South County East Area Study

The recommendation from the South County East Area Study for the opportunities in Narragansett and South Kingstown is to further develop the NWA option and to estimate potential implementation costs for each area.

The wires option has been assessed and estimated for the South County East area need. The wires option can now be compared to the NWA option the Company will source from the market to determine which option is the most prudent investment to implement.

9.2 Narragansett 42F1 NWA

This section details the Narragansett 42F1 NWA opportunity.

9.2.1 Background

This potential NWA opportunity, the Narragansett 42F1 NWA, intends to provide load relief in the Town of Narragansett by deferring or removing the need for feeder line work and reconfiguration on the Bonnet 42F1 feeder.

The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Feeder 42F1 is projected to be loaded above summer normal ratings by 2024 and lacks useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town.

9.2.2 Timeframe

The Company expects that the Narragansett 42F1 NWA timeframe will span seven years from 2024 to 2030, which is the maximum amount of time based on the current peak load forecast that the substation and feeder upgrade can be deferred with this solution. There is the potential for a partial or continued NWA solution following 2030 with the Narragansett 42F1 NWA; however, this option has not been assessed at this time.

9.2.3 Result of NWA RFP

The Company issued an RFP for the Narragansett 42F1 NWA opportunity in calendar year 2018 and evaluated the received bid submissions from third-party solution providers in calendar year 2019. Please see Appendix 8 for the Narragansett 42F1 NWA RFP document, which also details the technical and area information for the Narragansett 42F1 NWA opportunity.

All NWA solution bids submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

9.2.4 Next Steps

As the timing for the NWA need is not until 2024, the window of opportunity for sourcing a potential NWA solution is still open.

The Company will proceed with investigating alternate solution pathways, which may include: refining the parameters of the need, re-engineering the RFP, a Company-sourced proposal, a Company-owned solution, or a partial NWA. The Company is still actively seeking potential NWA solutions for this opportunity.

9.3 Narragansett 17F2 NWA

This section details the Narragansett 17F2 NWA opportunity.

9.3.1 Background

This NWA opportunity, the Narragansett 17F2 NWA, intended to provide load relief in the Town of Narragansett by deferring or removing the need for feeder line work and reconfiguration on the Wakefield 17F2 feeder.

9.3.2 Result of NWA RFP

The Company issued an RFP for the Narragansett 17F2 NWA opportunity in calendar year 2018 and evaluated the received bid submissions from third-party solution providers in calendar year 2019. Please see Appendix 9 for the Narragansett 17F2 NWA RFP document, which also details the technical and area information for the Narragansett 17F2 NWA opportunity.

All NWA solution bids submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

9.3.3 Next Steps

The need timing for this NWA opportunity is 2021. Therefore, the window of opportunity for sourcing a potential NWA solution is closed. This is because third-party solution providers, on average, require twelve to eighteen months lead time from the in-service date. The 2020 SRP Report would be the last chance to propose an NWA project for this opportunity.

The Company will proceed with the wires option for the Narragansett 17F2 system need.

9.4 South Kingstown NWA

This section details the South Kingstown NWA opportunity.

9.4.1 Background

This potential NWA opportunity, the South Kingstown NWA, intends to provide load relief in the Town of South Kingstown by deferring or removing the need for feeder line work and reconfiguration on the Peace Dale 59F3 and Kenyon 68F2 feeders.

The western section of the Town of South Kingstown is supplied mostly by (3) 12.47 kV distribution feeders. Feeders 59F3 and 68F2 are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town.

9.4.2 Timeframe

The Company expects that the South Kingstown NWA timeframe will span nine years from 2022 to 2030, which is the maximum amount of time based on the current peak load forecast that the substation and feeder upgrade can be deferred with this solution. There is the potential for a partial or continued NWA solution following 2030 with the South Kingstown NWA; however, this option has not been assessed at this time.

9.4.3 Result of NWA RFP

The Company issued an RFP for the South Kingstown NWA opportunity in calendar year 2019 and evaluated the received bid submissions from third-party solution providers in calendar year 2019. Please see Appendix 10 for the South Kingstown NWA RFP document, which also details the technical and area information for the South Kingstown NWA opportunity.

All NWA solution bids submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

9.4.4 Next Steps

As the timing for the NWA need is not until 2022, the window of opportunity for sourcing a potential NWA solution is still open.

The Company will proceed with investigating alternate solution pathways, which may include: refining the parameters of the need, re-engineering the RFP, a Company-sourced proposal, a Company-owned solution, or a partial NWA. The Company is still actively seeking potential NWA solutions for this opportunity.

9.5 Path Forward with South County East NWA

The Company is committed to sourcing viable solutions for potential NWA opportunities. The Narragansett 17F2 NWA opportunity is no longer feasible based on timing constraints for sourcing an NWA solution. However, the windows of opportunity for the Narragansett 42F1 NWA and South Kingstown NWA are still open based on their need timing.

The Company recognizes a need for improvements to the NWA RFP and evaluation process to promote more opportunities for successful NWAs. The Company commits to the following actions with the intent of increasing the viability of the South County East NWA Projects:

1. Analyze whether there are additional benefit streams available that can be combined with NWAs to create more cost-effective solutions.
2. Refine the parameters of the need to capture additional benefits, if applicable.
3. Assess the option of a Company-sourced proposal, where the Company formulates a proposal with specific parameters to be fulfilled by the market, which would be used to compare against third party solutions.

The Company commits to investigating viable alternate solution pathways for the Narragansett 42F1 and South Kingstown NWA opportunities.

10. Rhode Island System Data Portal

This section details the Rhode Island System Data Portal and associated resources.

The Portal is an interactive online mapping tool developed by the Company. The Portal provides specific information for select electric distribution feeders and associated substations within the Company's electric service area in Rhode Island. This information includes feeder characteristics such as geographic locations, voltage, feeder ID, planning area, substation source, approximate loading, and available distribution generation hosting capacity.

The Portal provides this information to stakeholders, customers, and third-party solution providers. The main target audience is third-party solution providers and the main goal of the Portal is to provide information in order to engage the market for cost-effective grid solutions to reduce costs for Rhode Island customers.

The Portal is part of SRP because SRP resources can include efforts that adhere to the Least-Cost Procurement goals and that these resources be complementary but distinct activities that have a common purpose of meeting electrical energy needs in Rhode Island. As the main goal of the Portal is to provide information in order to engage the market for cost-effective grid solutions to reduce costs for Rhode Island customers, the Portal is considered a complementary activity to meet electrical energy needs and therefore falls under LCP standards and goals.

Costs related to Portal maintenance and routine operation of existing Portal aspects and work by full-time employees (FTEs) are included in the current rate case under Docket 4770. Only new enhancements to the Portal are covered in the annual SRP Report.

A public landing page for the Portal is located on the customer-facing National Grid website[10].

The 2018 SRP Report included a proposal for the initial work on the Portal. The initial version of the Portal went live on June 30, 2018. The initial version of the Hosting Capacity Map resource of the Portal went live on September 28, 2018.

The 2019 SRP Report included a proposal for additional enhancement work on the Portal. Initial posting of redacted area studies to the Company Reports tab started in January 2019. The initial version of the NWA tab resource of the Portal went live on June 11, 2019.

10.1 Portal to Date

[10] See Rhode Island System Data Portal. *National Grid US*, National Grid USA Service Company, Inc., 2018, www.nationalgridus.com/Business-Partners/RI-System-Portal
.

To date, the Portal includes tabs that detail select Company reports, a distribution assets overview map, a heat map, and a hosting capacity map.

The Distribution Assets Overview tab contains a map that displays specific electric distribution feeder and substation information, summer normal ratings, and up-to-date recorded loading and forecasted loading.

The Heat Map tab contains an interactive color-coded map of distribution feeders based on forecasted load compared to summer normal rating. The heat map provides information on circuits that would benefit from DER interconnection for load relief, and on circuits that have existing capacity for EV charging stations, heat pumps, and other beneficial electrification opportunities.

The Hosting Capacity tab contains an interactive map of distribution feeders based on interconnected DG and in-progress DG projects. The hosting capacity map also contains information on substation ground fault overvoltage protection (3V0) status: if 3V0 is installed at a substation or if 3V0 is in construction or slated for construction and the proposed in-service date. Installation of 3V0 makes a substation transformer "DG ready".

10.2 Enhancing the Portal

The Company commits to further enhancement of the Portal by completing the following actions:

- Begin coordination work with the Company's proposed Grid Modernization Plan regarding inclusion of hourly (8,760 hours) data in addition to peak load data if the Grid Modernization Plan with this update is approved for funding.

Coordination work regarding inclusion of hourly data is a step toward providing more effective information to the market.

10.3 Funding Request for the Portal

The Company estimates that no additional funding will be required for the Portal enhancements stated above for calendar year 2020.

11. SRP Market Engagement

This section provides information regarding the Company's outreach and market engagement efforts with respect to SRP.

SRP Market Engagement aims to raise awareness and perform outreach and engagement for the Rhode Island System Data Portal, NWA-related activities not covered by FTE work, and third-party solution providers.

Outreach and engagement for activities specific to NWA, such as NWA RFPs, are already included in the work by FTEs dedicated to the development and pursuit of NWA opportunities and solutions. These FTEs are covered by the rate case.

The purpose of the SRP Outreach and Engagement Plan is to raise awareness of and drive engagement with the Rhode Island System Data Portal and associated map resources to all appropriate Rhode Island parties, with the primary target audience being third-party solution providers. These third-party solution providers include potential DER solution providers. The Outreach and Engagement Plan is in the SRP because it supports an SRP initiative, the Rhode Island System Data Portal. The SRP Outreach and Engagement Plan is not included in any other Company program or plan because SRP Outreach and Engagement drives directly at engagement with DER providers to seek solutions for NWA projects.

There may be additional opportunities for installations of alternative solutions and technologies that reduce peak load outside of National Grid's consideration and proposal of cost-effective NWA projects. This SRP Outreach and Engagement Plan will nurture these inherent opportunities with the work the Company is doing on the Portal, and to encourage and engage DER solution providers to support the strategic deployment of these solutions to benefit constrained areas.

Such engagement will enable third-party solution providers and vendors to more easily access available information about National Grid's electric distribution system in Rhode Island and therefore further enable these solution providers to create, submit and develop innovative energy solutions for Rhode Island customers. The SRP Outreach and Engagement Plan upholds the commitment of National Grid and the State of Rhode Island to advance a more reliable, safe, and cost-effective energy landscape for residents and businesses of Rhode Island.

11.1 Market Engagement Channels

With respect to SRP and NWA activities, the Company engages with the market, vendors, and third-party solution providers through the following communication channels:

- Procurement and Contracting Platform: National Grid posts RFPs, receives vendor bids, and sends formal vendor communications in an official forum via its procurement and contracting digital platform for vendors.

- Rhode Island System Data Portal: National Grid posts information regarding NWAs and NWA RFPs to the Portal.

- Rhode Island System Data Portal Outreach: National Grid promotes awareness and drives engagement to the Portal via the SRP Outreach and Engagement Plan initiative and additionally detailed in Section 11.2.

- NWA Vendor Stakeholder Monthly Calls: National Grid directly interacts with vendor stakeholders in monthly calls to raise awareness on the NWA development and bid submission process and to inform vendor stakeholders on upcoming and current NWA opportunities. National Grid also hosts Q&A during these calls and receives feedback relevant to NWA.

The Company is additionally exploring outreach via social media with regard to NWA and how different industry or professional social media platforms can be best utilized for enhanced SRP and NWA outreach and engagement.

11.2 Market Engagement Activities to Date

To date, the Company has focused SRP market engagement activities on the Rhode Island System Data Portal.

Please see Appendix 5 for the 2019 Marketing and Engagement Plan.

The Company has developed and implemented an SRP Monthly Marketing Report that it circulates with the SRP TWG stakeholders. This is included in Appendix 6 – 2019 SRP Marketing and Engagement Year-to-Date Results. These year-to-date results demonstrate the impact of the SRP Outreach and Engagement Plan.

Market engagement activities to date, organized by the business-to-business (B2B) outreach and engagement channels, are as follows:

- **Webinars**
  The Company has launched educational webinars for third-party solution providers in Rhode Island. The Company utilizes email marketing and online registration to raise awareness for those webinars. Four webinars have been hosted in calendar year 2019.

- **In-Person Demonstrations**
  The Company hosts in-depth technical in-person demonstrations for third-party solution providers in Rhode Island. In-person demos are similar to webinars in purpose, with the added benefit that hands-on guidance can be provided to the vendor during the demonstration. The Company hosted two in-person demonstrations in calendar year 2019.

- **Email**
  Email marketing helps to maintain and raise awareness for current and new vendors, notify vendors of any major changes or updates to the Portal, and informs vendors that the Portal is a useful tool to use as part of project and proposal development.

  The Company has performed four email campaigns in calendar year 2019, with one campaign performed per quarter, to maintain awareness of the Portal among the current vendor base. The Company has also leveraged additional available promotional opportunities through the RI Solar Stakeholders mailing list, via outreach to the RI OER, and through in-person meetings.

- **Digital Advertisements**
  The Company has developed a digital advertising campaign to raise awareness of the RI System Data Portal to increase Google search ranking and to serve up Portal ads to developers in the State. This campaign started in September 2018. A customer-facing webpage was developed on the National Grid website to serve as a front door to the Portal and to make it easier for vendors to find.

- **Paid Search Terms**
  Paid search terms enable the Portal to be populated much higher in a web search results list. This search result improvement allows vendors to more easily receive search results relevant to the Portal. A web search is another venue where new vendors can learn about the Portal through the use of related terminology.

  The Company has seen all four of the paid search terms rise to 2^{nd} position in a Google search results list in calendar year 2019.

- **Social Media Engagement**
  Posting important updates on a business-oriented social media platform helps to maintain awareness of the Portal and to concisely call out important changes to the Portal for vendors.

  National Grid has posted two messages regarding the Rhode Island System Data Portal to the Company pages of LinkedIn to enable another venue of outreach to new and existing vendors in calendar year 2019.

- **Vendor Contact List**
  Procuring vendor contact lists enables National Grid to directly contact vendors, especially new vendors, who are not currently being reached via email marketing or web advertisements. These vendor contact lists are used to communicate to vendors about Portal webinars, in-person demonstrations, or major updates to the Portal.

National Grid has procured three vendor contact lists in calendar year 2019, with two of three being free and one being a paid national vendor list.

- **Contact Channels**
  National Grid has created a dedicated email distribution list in calendar year 2019 for all appropriate inquiries related to the Portal.

Please see Appendix 6 for the 2019 SRP Marketing and Engagement Plan Year-to-Date Results for further detail and which contains the results and metrics from market engagement activities for the current year to date.

11.3 Market Engagement Proposal

The Company requests approval to continue the proposed SRP Outreach and Engagement Plan through calendar year 2020. Please see Appendix 7 for the proposed 2020 SRP Outreach and Engagement Plan text.

The Company requests approval for the proposed budget of $69,370 to support SRP Market Engagement and the SRP Outreach and Engagement Plan initiative in 2020.

The Company strives to nurture the inherent opportunities with the work the Company is doing on the Portal and to encourage DER solution providers to support the strategic deployment of these solutions to benefit constrained areas. The Company notes that there is still a significant proportion of vendors attendees in the in-person demonstrations and webinars, 50% as of August 2019, who report that the demo or webinar was the first time hearing of or seeing the Portal. The Company interprets this figure as being far from market saturation for awareness and therefore considers the continuation of the SRP Outreach and Engagement Plan as necessary.

The proposed SRP Outreach and Engagement Plan will continue to promote the Portal. The 2020 SRP Outreach and Engagement Plan will build on the results of the 2019 SRP Marketing and Engagement Plan.

11.4 Market Engagement Funding Plan

The Company estimates that a total of $69,370 will be needed to support SRP Market Engagement and the SRP Outreach and Engagement Plan initiative in 2020.

The Company will need funding to support the creation and dissemination of marketing materials and tracking mechanisms and for marketing vendor payment. This is captured in the Materials and Vendors category in the table below.

The Company will need funding to support program planning and administration, which is associated with the management of materials development within the Company and with vendors and of the tracking and evaluation processes to determine the initiative's effectiveness. This is captured in the Program Planning and Administration category in the table below.

Table 7: SRP Market Engagement Funding Plan

Category	Cost
Materials and Vendors	$41,370
Program Planning and Administration	$28,000
Total	**$69,370**

12. Coordination between SRP and other Programs

The Company recognizes that improved synchronization between SRP and Power Sector Transformation (PST), the Energy Efficiency Program Plan (EE Plan), the Infrastructure, Safety and Reliability Plan, the Grid Modernization Plan (GMP), and the Advanced Metering Functionality (AMF) Business Case is necessary and intends to maintain and improve coordination between these filings.

Therefore, the Company commits to continued stakeholder engagement and continued participation in enhanced discussions regarding SRP, NWA, and related policy and programs with stakeholders. These enhanced discussions are held in the SRP TWG meetings and related sessions which include in-depth topical deep dives, process reviews, and plan development negotiation.

The Company also commits to continue its efforts to actively avoid double-counting shareholder incentives in SRP programs and projects. Coordination with other Company programs helps to prevent double-counting such incentives.

12.1 Coordination with Power Sector Transformation

This section describes how SRP coordinates with the Power Sector Transformation Phase One Report[11] goals and recommendations. Please refer to the PST Phase One Report for the full details on the goals and recommendations.

The PST Phase One Report details the following goals:

1. **Control the long-term costs of the electric system.** The regulatory framework should promote a broad range of resources to help right-size the electric system and control costs for Rhode Islanders. Today's electric system is built for peak usage. New technology provides us with more ways to meet peak demand and lower costs.

SRP has the potential to control the long-term costs of the electric system by proactively searching for potential NWA opportunities to be implemented on the electric distribution grid instead of the traditional wires option if they are at a lower cost to customers. Such NWA opportunities may include technologies and methodologies such as demand response, solar, energy storage, combined heat and power, microgrid, conservation or energy efficiency measure, and other DERs. These technologies can help increase electric grid reliability through implementation as cost-effective and safe solutions in place of the traditional wires option, all aspects of which readily align with controlling the long-term costs of the electric system.

2. **Give customers more energy choices and information.** The regulatory framework should allow customers to use commercial products and services to reduce energy expenses, increase renewable energy, and increase resilience in the face of storm outages. Clean energy technologies are becoming more affordable. Our utility rules should allow customers to access solutions to manage their energy production and use.

SRP provides customers with more energy choices and information through programs such as NWA participation opportunities. NWAs have the potential to reduce energy expenses by providing a cost-effective solution in place of a traditional wires option. NWA resources include and depend on renewable energy opportunities to provide unique benefits than a wires option. Properly configured NWA resources could provide resilience from outages as compared to the traditional wires option.

3. **Build a flexible grid to integrate more clean energy generation.** The regulatory framework should promote the flexibility needed to incorporate more clean energy resources into the electric grid. These resources would help Rhode Island meet the greenhouse gas emission reduction goals specified in the Resilient Rhode Island Act of

[11] "Rhode Island Power Sector Transformation: Phase One Report to Governor Gina M. Raimondo." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Division of Public Utilities and Carriers, Office of Energy Resources, and the Public Utilities Commission, Nov. 2017, www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf.

2014 and consistent with Governor Raimondo's goal of 1,000 megawatts of clean energy, equal to roughly half of Rhode Island's peak demand, by 2020.

SRP is designed to build a flexible grid to integrate more clean energy generation through NWA opportunities, initiation of the Rhode Island System Data Portal, and engagement with third-party solution providers. The 2018 SRP Report commenced work on the Portal, an interactive tool that provides information to stakeholders, customers, and third parties regarding the status of the Company's distribution grid. This tool enables third-party solution providers to proactively identify areas on the electric distribution grid in Rhode Island where NWA or other opportunities may be implemented. Application of such NWA technologies, as described previously, can enhance the flexibility of the electric grid, such as with battery storage technology, or directly contribute to more clean energy generation, such as with wind or solar technologies.

The PST Phase One Report also details the following recommendations:

1. **Synchronize filings related to Distribution System Planning.** National Grid should begin filing the ISR and SRP as two linked, synchronized, and cross-referenced Distribution System Planning (DSP) filings each year. Linking these two filings and including key DSP-related content will: (1) provide increased transparency and a codified mechanism for stakeholder and regulatory input into the improvement of DSP analytics and tools over time, and (2) enable the Commission and stakeholders to consider investments proposed in the ISR and SRP in a comprehensive and holistic manner. Coordinating these filings should account for the sequencing necessary by National Grid to develop the plans, including considerations related to the differing planning horizons associated with infrastructure projects versus NWA. ISR/SRP filings should include the following elements:
    - Methodologies, assumptions, and results of the annual forecasting process;
    - Any amendments to customer and third-party data access plans and procedures;
    - Proposed updates to the Rhode Island DSP Data Portal based on stakeholder input; and
    - Description of updates and improvements to publicly-provided datasets such as heat and hosting capacity maps.

SRP has synchronized with Distribution System Planning and the ISR filing to a certain extent, in that potential NWA opportunities are screened for as a standard part of DSP and that SRP takes into account the annual electric peak load forecasting, as seen in Sections 7 and 8. The Company recognizes that improved synchronization between SRP and Distribution System Planning and the ISR filing is necessary. The Company is improving coordination between the SRP, ISR, and EE filings in internal calls, discussions, cross-department review requests, and other active coordination efforts. The Company has also improved stakeholder engagement and participates in enhanced discussions on SRP, NWA, and related policy and programs in the SRP TWG monthly meetings, which include the SRP TWG members, and NWA Quarterly meetings, which include the Division, OER, and National Grid. The work the Company has completed on the Portal to date and proposals for enhancement, which developed from stakeholder discussion and input, are described in Section 10.

2. **Improve forecasting.** National Grid should include detailed information on its forecasts used for DSP in annual SRP/ISR filings. Inclusion of forecasts within the SRP/ISR filings will provide regulators and stakeholders with the opportunity to provide ongoing review and feedback. In addition, National Grid should implement a robust stakeholder engagement plan during forecast development to provide policymakers and third parties the opportunity to review and provide input on forecasting assumptions and methodology.

This SRP Report currently includes information on forecasted electric load growth, as seen in Section 7, for the main purpose of identifying and coordinating with potential NWA opportunities. This SRP Report also includes the Rhode Island Electric Peak (MW) Forecast in Appendix 2 for additional, holistic information. The Company intends to implement robust stakeholder engagement and discussion on the electric forecasting process. Specifically, the Company will host a meeting in November 2019 to review the electric forecasting process and engage and discuss the forecasting process with stakeholders. The Company is open to hosting follow-up meetings to further engagement with stakeholders on electric forecasting through 2020 as well.

3. **Establish customer and third-party data access plans.** National Grid should include and seek approval of a plan for establishing and improving customer and third-party data access in the upcoming rate case. Updated data access plans should be included in future annual SRP/ISR filings. Inclusion of data access plans within the SRP/ISR filings will provide regulators and stakeholders with the opportunity to provide ongoing review and feedback.

SRP establishes customer and third-party data access through the Rhode Island System Data Portal. The 2019 SRP Report proposed further work on the Portal to improve data access for external parties. The 2019 SRP Report also proposed commitment to discussion on posting NWA RFPs and to inclusion of redacted area studies in the Portal. SRP does not currently maintain a specific data access plan, as a document or otherwise. The Company will commit to development and implementation of a data governance plan in coordination with the work on the AMF and GMP filings and will continue stakeholder engagement and discussion.

4. **Compensate locational value.** State policymakers and regulators should develop an implementation strategy for locational incentives/value of DERs in Rhode Island, in consultation with National Grid and stakeholders.

The 2019 SRP Report presented the Company's research and findings on locational incentive analysis for Rhode Island. The stakeholder review process regarding Rhode Island Locational Incentives and location-based avoided costs is ongoing. The Company commits to stakeholder engagement and discussion regarding locational incentives through in Rhode Island by July 31, 2020 through the SRP TWG meetings and other relevant sessions, and to determine whether the current methodology should be modified.

12.2 Coordination with Energy Efficiency

The Company continues coordination between SRP and customer offerings in the Energy Efficiency Program Plan to ensure that efforts, projects, and programs are optimal and not duplicated. The Company coordinates SRP and EE planning efforts so that opportunities for targeted EE are considered in NWA opportunity development.

The SRP Report and its NWA proposals are separate and unique from the Energy Efficiency Program Plan customer measures because NWA projects are targeted solutions for electric grid reliability as compared to energy efficiency's goal of bulk energy savings from customers for the regional electric grid. These two main differences are illustrated by a difference in scope of area, feeder- or substation-level for SRP and state or regional for energy efficiency, and in scope of intent, electric grid reliability for SRP via NWA projects and energy savings for EEP via energy efficiency measures and programs.

As is the practice now and going forward, energy efficiency and demand response are examined during National Grid's distribution planning process as part of the development of NWA opportunities. This assessment of energy efficiency and demand response for NWAs occurs before the Company goes out to market with RFPs for solution bids from third-party solution providers. Energy efficiency and demand response may be deployed as part of an NWA solution so long as the targeted energy efficiency or demand response programs are least-cost, cost-effective, reliable, and technically feasible for the electric system need. The Company ensures cost-competitive utilization of targeted DR by evaluating market prices and comparing third-party demand response proposals to the incremental costs of targeted DR which would build upon National Grid's existing ConnectedSolutions program.

As energy efficiency is the least-cost resource, the Company will look for opportunities where it can target energy efficiency to create multifaceted benefits for customers. For example, the Company can utilize the increased visibility from the Rhode Island System Data Portal to target energy efficiency and demand response in areas that would benefit from load reduction. Other examples may include enhanced or targeted community initiatives or enhanced marketing for ConnectedSolutions, the Company's demand response program.

The Company also maintains synchronization and clear communications between the SRP TWG and the EE TWG: The National Grid program leads for the EE Plan and for SRP attend each other's TWG meetings, coordinate via email, and SRP additionally provides an update in a dedicated time slot in the EE TWG meeting.

12.3 Coordination with Infrastructure, Safety and Reliability

The Company prepares area studies to identify reliability and safety needs and associated solution options and recommendations for the Electric Distribution business in Rhode Island. The solutions identified in area studies can include both wires and non-wires alternatives. After an analysis of all wires and non-wires options identified, the Company recommends the solution that is the least cost option that will meet the needs identified in the area studies. If the recommended solution is a non-wires alternative, progression of the bidding, approval and implementation processes will progress through the SRP Report. If the recommended solution is a wires alternative, it may be progressed through the Electric ISR Plan at some point in the future.

Please see Section 8 for further detail regarding the planning process and coordination.

The Company is therefore coordinated between the SRP Report and ISR Plan with regard to NWA opportunity planning and development in parallel consideration to a wires solution investment.

12.4 Coordination with Grid Modernization and AMF

The SRP team is tracking the development and implementation of the Grid Modernization Plan and Advanced Metering Functionality Business Case filings to ensure future coordination is maintained with the outcome of these plans. The Company will coordinate the SRP Report with the GMP and AMF filings to ensure that efforts, projects, and programs are not being duplicated and to ensure cohesive and comprehensive plan framework and implementation.

The SRP team is aware that AMF proposal includes data availability and access. Such data can further improve planning and development of potential NWA opportunities. Additionally, the SRP team understands that third-party data access to AMF may be required for the implementation of certain NWA projects. For example, the addition of smart meter data realized from the AMF investment can provide planners with more granular data and thusly provide the ability to aide in forecasting and strategic planning. The SRP and NWA teams are therefore coordinating with the development and implementation of the AMF filing with these specific data access themes in mind, in addition to following the AMF Business Case in general.

The SRP team is aware that Grid Modernization discusses functional topics such as EV, DG, energy storage, demand response, and other technologies and methodologies through its development and implementation. The SRP and NWA teams are therefore synchronized with the development and implementation of the GMP to ensure coordination is maintained.

The Company has internal, regular check-in meetings and additional one-on-one meetings to stay synchronized and coordinated across Company programs and filings, such as between SRP, GMP, and AMF. The Company maintains overall coordination between SRP and the GMP and AMF filings.

13. Miscellaneous Provisions

A. Other than as expressly stated herein, this Settlement establishes no principles and shall not be deemed to foreclose any party from making any contention in any future proceeding or investigation before the PUC.

B. This Settlement is the product of settlement negotiations. The content of those negotiations is privileged, and all offers of settlement shall be without prejudice to the position of any party.

C. Other than as expressly stated herein, the approval of this Settlement by the PUC shall not in any way constitute a determination as to the merits of any issue in any other PUC proceeding.

The Parties respectfully request the PUC approve this Stipulation and Settlement as a final resolution of all issues in this proceeding.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY
D/B/A NATIONAL GRID

10/15/2019

By its Attorney, Date
Raquel J. Webster

Appendices

Appendix 1 – Least Cost Procurement Standards with 2018 Revisions Approved in Docket No. 4684

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

LEAST COST PROCUREMENT STANDARDS

CHAPTER 1 – Energy Efficiency Procurement

1.1. Introduction

A. Energy Efficiency (EE) Procurement, as mandated by §39-1-27.7, is intended to complement system reliability and supply procurement as provided for in §39-1-27.8, with the common purpose of meeting electrical and natural gas energy needs in Rhode Island in a manner that is optimally cost-effective, reliable, prudent, and environmentally responsible.

B. In order to adhere to the principles set forth in §39-1-27.7, and to meet Rhode Island's energy system needs in a least cost manner, the EE Standards set forth guidelines for the development of least cost energy efficiency plans.

1.2. Definitions

A. Energy Efficiency

i. Energy efficiency is defined as the reduction of energy consumption or strategic and beneficial management of the time of energy use within a defined system. A system may be a residence; a place of business; a public accommodation; or an energy production, delivery, and end-use consumption network.

ii. Energy Efficiency Plans[1] should be designed, where possible, to complement the objectives of Rhode Island's energy efficiency; renewable energy; and clean energy programs, and describe their interaction with them, including, but not limited to, the System Reliability Procurement Plan; the Renewable Energy Standard; the Renewable Energy Growth Program; the Net Metering Program; and the Long-Term Contracting for Renewable Energy Standard. Energy Efficiency Plans should also be coordinated, where possible, with other applicable energy procurement, planning, and investment programs, including, but not limited to, Standard Offer Supply Procurement.

iii. Innovation. Energy Efficiency Plans should address new and emerging issues as they relate to Least Cost Procurement (e.g., CHP, strategic electrification, integration of grid modernization, gas service expansion, distributed generation and storage technologies, energy efficiency services for non-regulated fuels, etc.), as appropriate, including how they may meet State policy objectives and provide system, customer, environmental, and societal benefits.

iv. Comprehensiveness.

The distribution company should consistently design programs and strategies to ensure that all customers have an opportunity to benefit comprehensively through types of measures or depth of services, realizing both near-term and

[1] Energy Efficiency Plans refers to both the EE Procurement Plan (or Three-Year Plan) and EE Program Plan (or Annual Plan), as applicable.

long-lived savings opportunities where appropriate, from expanded investments in this low-cost resource. The programs should be designed and implemented in a coordinated fashion by the distribution company, in active and ongoing consultation with the Energy Efficiency and Resource Management Council (Council).

a. Equity. The portfolio of programs proposed by the distribution company should be designed to ensure that different sectors and all customers receive opportunities to participate and secure efficiency resources lower cost than the cost of supply.

B. Cost-Effectiveness

i. The distribution company shall assess the cost-effectiveness of measures, programs, and portfolios according to the Rhode Island Benefit Cost Test (RI Test) that was approved by the Public Utilities Commission (PUC) in Docket 4600. The distribution company shall, after consultation with the Council, propose the specific benefits and costs from the Rhode Island Benefit Cost Framework to be reported, and factors to be included, in the RI Test and include them in Energy Efficiency Plans. These benefits should include resource impacts, non-energy impacts, distribution system impacts, economic development impacts, and the value of greenhouse gas reductions, as described below. The accrual of specific non- energy impacts to only certain programs or technologies, such as income-eligible programs or combined heat and power, may be considered.

ii. The distribution company shall apply the following principles when developing the RI Test:

a. **Efficiency as a Resource.** EE is one of many resources that can be deployed to meet customers' needs. It should, therefore, be compared with both supply-side and demand-side alternative energy resources in a consistent and comprehensive manner.

b. **Energy Policy Goals.** Rhode Island's cost-effectiveness test should account for its applicable policy goals, as articulated in legislation, PUC orders, regulations, guidelines, and other policy directives.

c. **Hard-to-Quantify Impacts.** Efficiency assessment practices should account for all relevant, important impacts, even those that are difficult to quantify and monetize.

d. **Symmetry.** Efficiency assessment practices should be symmetrical, for example, by including both costs and benefits for each relevant type of impact.

e. **Forward Looking**. Analysis of the impacts of efficiency investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of efficiency measures with those that would occur absent the efficiency investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis.

f. **Transparency.** Efficiency assessment practices should be completely transparent, and should fully document and reveal all relevant inputs, assumptions, methodologies, and results.

iii. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of CO_2 mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative. The RI Test shall also include any other utility system costs associated with reasonably anticipated future greenhouse gas reduction requirements at the state, regional, or federal level for both electric and gas programs. A comparable benefit for greenhouse gas reduction resulting from natural gas or delivered fuel energy efficiency or displacement may be considered. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above. The RI Test may also include the costs and benefits of other emissions and their generation or reduction through Least Cost Procurement.

iv. Benefits and costs that are projected to occur over the term of the Energy Efficiency Plans shall be stated in present value terms in the RI Test calculation using a discount rate that appropriately reflects the risks of the investment of customer funds in energy efficiency; in other words, a discount rate that indicates that energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk. The discount rate shall be reviewed and updated in the Energy Efficiency Plans, as appropriate, to ensure that the applied discount rate is based on the most recent information available.

v. The distribution company shall provide a discussion of the carbon impacts efficiency and reliability investment plans will create, whether captured as benefits or not.

vi. The distribution company shall measure cost effectiveness according to the RI Test. In order to assess the impact of adopting the RI Test, the distribution company shall provide a comparison of its cost-effectiveness analysis under the Total Resource Cost (TRC) Test, as approved by the PUC in Docket No. 4580, to the RI Test, as adopted in this proceeding as part of its 2018-2020 Three-Year Plan and for each 2018, 2019 and 2020 Annual Plan filing.

C. Less than the Cost of Supply

i. The distribution company shall assess the cost of energy supply and the cost of energy efficiency using all applicable costs enumerated in the Rhode Island Benefit Cost Framework approved by the PUC in Docket No. 4600A and the Rhode Island Test, as updated periodically and approved by the PUC. The distribution company shall, after consultation with the Council, propose specific costs to be included in the cost of energy supply and energy efficiency in Energy Efficiency Plans. These costs should include applicable resource impacts, non-energy impacts, distribution system impacts, economic development impacts, greenhouse gas impacts, among others. The accrual of applicable specific non-energy costs to only certain programs or technologies, such as income-eligible programs or combined head and power, may be considered.

ii. The cost of supply shall include costs associated with generation, transmission, and distribution of electricity. Additional energy supply shall mean supply that would be incremental to marginal energy supply.

a. The distribution company shall describe which costs in the cost-effectiveness test were included in the cost of supply and which costs are included in the cost of energy efficiency. For any impacts that are not included in either the cost of supply or the cost of energy efficiency, the distribution company shall describe why they are not included.

D. Reliable

  i. Build on prior plans. Energy Efficiency Plans shall describe the recent energy efficiency programs offered by the distribution company and highlight how the Energy Efficiency Plans supplement and expand upon these offerings at the appropriate level of detail, including, but not limited to, new measures, implementation strategies, measures specifically intended for demand or load management, and new programs as appropriate.

    a. Build on prior programs. Distribution company program development shall proceed by building upon what has been learned to date in distribution company program experience, systematically identifying new opportunities and pursuing comprehensiveness of measure implementation, as appropriate and feasible.

E. Prudent

  i. Plan based on potential assessments. The distribution company shall use the Council's Opportunity Report, as issued on July 15, 2008, or other assessments of potential, as resources in developing its Three-Year Plan. The distribution company shall include in its Three-Year Plan an outline of proposed strategies to supplement and build upon these assessments of potential.

  ii. Unlocks capital and effectively uses funding sources. Energy Efficiency Plans shall include a section outlining and discussing new strategies to make available the capital needed to effectively overcome barriers to implement projects in addition to direct financial incentives provided in order to cost-effectively achieve the Least Cost Procurement mandate. Such proposed strategies shall move beyond traditional financing strategies and shall include new capital availability strategies and partnerships that effectively overcome market barriers in each market segment in which it is feasible to do so.

  iii. Integration. Energy Efficiency Plans shall address how the distribution company plans to integrate gas and electric energy efficiency programs to optimize customer energy efficiency and provide benefits from synergies between the two energy systems and their respective programs.

  iv. Three-Year Plans shall be developed to propose strategies to achieve the energy efficiency savings targets that shall be proposed by the Council and approved by the PUC for that three-year period. Such strategies shall secure energy, capacity, and system benefits and also be designed to ensure the programs will be delivered successfully, cost-effectively, and cost-efficiently over the long term. In addition to satisfying other provisions of these Standards, the Three- Year Plan shall contribute to a sustainable energy efficiency economy in Rhode Island, respond to and transform evolving market conditions, strive to increase participation, and provide widespread consumer benefits.

  v. Energy Efficiency investments shall be made on behalf of all customers. This will ensure consistency with existing program structure under which all customers pay for, and benefit from, Rhode Island's efficiency programs.

    a. Efficacy. All efforts to establish and maintain program capability shall be done in a manner that ensures quality delivery and is economical and efficient. The Utility shall include wherever possible and practical partnerships with existing educational and job training entities.

F. Environmentally Responsible

i. Environmental responsibility is indicated by the procurement of energy savings, compliance with State environmental policies, and the proper valuation of greenhouse gas reduction benefits.

1.3. EE Procurement Plan

A. The distribution company Energy Efficiency and Conservation Procurement Plan (Three-Year Plan) submitted on September 1, 2008, and triennially thereafter on September 1, shall propose overall budgets and efficiency targets for the three years of implementation beginning with January 1 of the following year. These budgets and targets shall be illustrative and provisional,[2] and shall guide Annual Energy Efficiency Plans over the three-year period.

B. The Three-Year Plan shall identify the strategies and an approach to planning and implementation of programs that will secure all cost-effective energy efficiency resources that are lower cost than supply, prudent and reliable, and consistent with the definitions provided herein. The Three-Year Plan shall contain sections that describe the following:

i. Strategies and Approaches to Planning.

ii. Cost-Effectiveness

iii. Prudency and Reliability

iv. Funding Plan and Initial Targets

a. The distribution company shall develop a funding plan using, as necessary, the following sources of funding to meet the budget requirement of the Three-Year Plan and fulfill the statutory mandate of Least Cost Procurement. The distribution company shall utilize, as necessary and available, the following sources of funding for the efficiency program investments:

(1) the existing System Benefits Charge (SBC);

(2) revenues resulting from the participation of energy efficiency resources in ISO-New England's forward capacity market (FCM);

(3) proceeds from the auction of Regional Greenhouse Gas Initiative (RGGI) allowances pursuant to R.I. Gen. Laws § 23-82-6;

(4) funds from any state; federal; or international climate or cap and trade legislation or regulation, including, but not limited to, revenue or allowances allocated to expand energy efficiency programs;

(5) a fully reconciling funding mechanism, pursuant to R.I. Gen. Laws § 39-1-27.7, which is a funding mechanism to be relied upon after the other sources as needed to fully fund cost-effective

[2] As the Three-Year Plan is illustrative and provisional, variances between Annual Energy Efficiency Plans and Three-Year Plans due to changes in factors such as, but not limited to, sales forecasts, funding sources, avoided costs, and evaluation results may be acceptable, subject to PUC review of Utility explanation for those variances.

electric and gas energy efficiency programs to ensure the legislative mandate to procure all cost effective efficiency that is lower cost than supply is met; and

(6) other sources as may be identified by the Council, the Office of Energy Resources (OER), and the distribution company.

b. The distribution company shall include a preliminary budget for the Three-Year Plan, covering the three-year period, that identifies the projected costs, benefits, and initial energy saving targets of the portfolio for each year. The budget shall identify, at the portfolio level, the projected cost of efficiency resources in cents/lifetime kilowatt- hours (kWh) or cents/lifetime million British thermal units (MMBtu). The preliminary budget and initial energy saving targets may be updated, as necessary, in the distribution company's Annual Energy Efficiency Plan.

v. Performance Incentive Plan Structure, pursuant to Section 1.5

1.4. <u>EE Program Plan</u>

A. The distribution company shall prepare and file a supplemental filing containing details of implementation plans by program for the next program year (Annual Energy Efficiency Plan or Annual Plan). Beginning in 2014, the Annual Plan shall be filed on October 15, except in years in which a Three-Year Plan is filed; in those years, the Annual Plan filing shall be made on November 1. The Annual Plan filings shall also provide for adjustment, as necessary, to the remaining years of the Three-Year Plan based on experience, ramp-up, and assessment of the resources available.

B. Principles of Program Design. The Annual Plan shall identify and contain programs proposed for implementation by the distribution company pursuant to the Three-Year Plan and which demonstrate consistency with the principles of program design described above in Section 1.2.

C. Cost-effectiveness. The distribution company shall propose a portfolio of programs in the Annual Plan that is cost-effective. Any program with a benefit-cost ratio greater than 1.0 (i.e., where benefits are greater than costs), should be considered cost- effective. The portfolio must be cost-effective and programs should be cost-effective, except as noted below.

i. The distribution company shall be allowed to direct a portion of proposed funding to conduct research and development and pilot program initiatives. These efforts will not be subject to cost-effectiveness considerations. However, the costs of these initiatives shall be included in the assessment of portfolio-level cost-effectiveness.

ii. The distribution company shall allocate funds to the Council and OER as specified in R.I. Gen. Laws § 39-2-1.2. These allocations will not be subject to cost-effectiveness considerations. However, these costs shall be included in the assessment of portfolio-level cost-effectiveness.

D. Parity. While it is anticipated that rough parity among sectors can be maintained, as the limits of what is cost-effective are identified, there may be more efficiency opportunities identified in one sector than another. The distribution company should design programs to capture all resources that are cost-effective and lower cost than supply. The distribution company should consult with the Council to address ongoing issues of parity

E. Final Funding Plan and Budget Amounts, Cost-Effectiveness, and Goals
   i. The distribution company shall include a detailed budget for the Annual Plan, covering the annual period beginning the following January 1, that identifies the projected costs; benefits; and energy saving goals of the portfolio and of each program. The budget shall identify, at the portfolio level, the projected total resource cost of efficiency resources in cents/lifetime kWh or cents/lifetime MMBtu.
   ii. The Annual Plans filed October 15 or November 1 will reflect program implementation experience and anticipated changes, shifts in customer demand, changing market costs, and other factors, including a discussion of market transformation impacts as noted above in Section 1. The annual detailed budget update shall include the projected costs, benefits, and energy saving goals of each program, as well as the total resource cost of efficiency resources in cents/lifetime kWh or cents/lifetime MMBtu.
   iii. The Annual Plan shall identify the energy cost savings and bill impacts that Rhode Island ratepayers will realize through its implementation.

F. Program Descriptions
   i. The distribution company shall, as part of its Annual Plan, describe each program, how it will reach its target market, and how it will be implemented. In these descriptions, the distribution company shall demonstrate, as appropriate, how the program is consistent with the principles of program design described above.
   ii. In addition to these basic requirements, the Annual Plan shall address, where appropriate, the following elements:
      a. comprehensiveness of opportunities addressed at customer facilities;
      b. integration of electric and natural gas energy efficiency implementation and delivery (while still tracking the cost-effectiveness of programs by fuel); energy efficiency opportunities for delivered fuels customers should be addressed to the extent possible;
      c. integration of energy efficiency programs with renewables and other System Reliability Procurement Plan elements;
      d. promotion of the effectiveness and efficiency levels of codes, standards, and other market transforming strategies; if the distribution company takes a proactive role in researching, developing and implementing such strategies, it may, after consultation with the Council, propose a mechanism to claim credit for a portion of the resulting savings;
      e. implementation, where cost-effective, of demand response and load management measures or other programs that are integrated into the electric and natural gas efficiency program offerings; such measures/programs will be designed to supplement cost-effective procurement of long-term energy and capacity savings from efficiency measures; and
      f. integration with non-wires alternatives.

G. Monitoring and Evaluation (M&E) Plan

i. The distribution company shall include an M&E Plan in its Annual Plan.

ii. This M&E Plan shall address at least the following:

a. savings verification, including, where appropriate, analysis of customer usage; such savings verification should also facilitate participation in ISO-NE's forward capacity market;

b. issues of ongoing program design and effectiveness;

c. any other issues, for example, efforts related to market assessment and methodologies to claim savings from market effects, among others;

d. a discussion of regional and other cooperative M&E efforts the distribution company is participating in, or plans to participate in; and

e. longer-term studies, as appropriate, to assess programs over time.

iii. The distribution company shall include in its M&E Plan any changes it proposes to the frequency and level of detail of distribution company program plan filing and subsequent reporting of results.

H. Reporting Requirements

i. The distribution company, in consultation with the Council, will propose the content to be reported and a reporting format that is designed to communicate clearly and effectively the benefits of the efforts planned and implemented, with particular focus on energy cost savings and program participation levels across all sectors, to secure all EE resources that are lower cost than supply.

I. Performance Incentive Plan, pursuant to Section 1.5

1.5. <u>Efficiency Performance Incentive Plan</u>

A. Pursuant to R.I. Gen. Laws § 39-1-27.7(e) and § 39-1-27.7.1, the distribution company shall have an opportunity to earn a shareholder incentive that is dependent on its performance in implementing the approved Annual Plan.

i. The distribution company, in consultation with the Council, will propose in its Three-Year Plan and subsequent Annual Plans a Performance Incentive (PI) Plan that is designed to promote superior distribution company performance in cost-effectively and efficiently securing for customers all efficiency resources lower cost than supply.

ii. The PI should be structured to reward program performance that makes significant progress in securing all cost-effective efficiency resources that are lower cost than supply while, at the same time, ensuring that those resources are secured as efficiently as possible.

iii. The distribution company PI model currently in place in Rhode Island should be reviewed by the distribution company and the Council. The distribution company and Council shall also review incentive programs and designs in other jurisdictions, including those with penalties and increasing levels of incentives based on higher levels of performance.

iv. The PI may provide incentives for other objectives that are consistent with the goals, including, but not limited to, comprehensiveness; customer equity; lifetime net benefits; increased customer access to capital; and market transformation.

B. The PI should be sufficient to provide a high level of motivation for excellent distribution company performance annually and over the three-year period of the Three-Year Plan, but structured so that customers receive most of the benefit from energy efficiency implementation.

C. The PI shall state clearly each specific objective it is designed to direct the distribution company to achieve and the reason it is needed to do so. The design of the PI shall be clear and focused, have clear metrics for determining performance, not duplicate incentives, and not provide multiple or different incentives for attaining the same objective.

1.6. <u>Role of the Council in Energy Efficiency Plan Development and Approval</u>

A. The Council shall take a leadership role in ensuring that Rhode Island ratepayers receive excellent value from the Three-Year Plan being implemented on their behalf. The Council shall do this by collaborating closely with the distribution company on design and implementation of the M&E efforts presented by the distribution company under the terms of Section 1.4.D and, if necessary, provide recommendations for modification that will strengthen the assessment of distribution company programs.

B. In addition to the other roles for the Council indicated in this filing, the distribution company shall seek ongoing input from, and collaboration with, the Council on development of the Three-Year Plan and Annual Plans, and on development of annual updates, if any, to the Three-Year Plan. The distribution company shall seek to receive the endorsement of the Energy Efficiency Plan by the Council prior to submission to the PUC.

C. The distribution company and the Council shall report to the PUC a process for Council input and review of its 2008 EE Procurement Plan and EE Program Plan by July 15, 2008, and triennially thereafter.

D. The Council shall vote whether to endorse the Three-Year Plan by August 15, 2008, and triennially thereafter. If the Council does not endorse the Three-Year Plan, then the Council shall document the reasons and submit comments on the Three-Year Plan to the PUC for their consideration in final review of the Three-Year Plan.

E. The distribution company shall, in consultation with the Council, propose a process for Council input and review of its Three-Year Plan and Annual Plan. This process is intended to build on the mutual expertise and interests of the Council and the distribution company, as well as meet the oversight responsibilities of the Council.

F. The distribution company shall submit a draft Annual Plan to the Council and the Division of Public Utilities and Carriers for their review and comment annually, at least one week before the Council's scheduled meeting prior to the filing date that year.

G. The Council shall vote whether to endorse the Annual Plan prior to the prescribed filing date. If the Council does not endorse the Annual Plan, the Council shall document its reasons and submit comments on the Annual Plan to the PUC for its consideration in final review of the Annual Plan.

H. The Council shall prepare memos on its assessment of the cost effectiveness of the Three-Year Plans and Annual Plans, pursuant to R.I. Gen. Laws §39-1-27.7(c)(5), and submit them to the PUC no later than three weeks following the filing of the respective Energy Efficiency Plans with the PUC.

CHAPTER 2 - System Reliability Procurement

2.1. Introduction

A. System Reliability Procurement (SRP), as mandated by R.I. Gen. Laws §39-1-27.7, is intended to complement energy efficiency and conservation procurement, and supply procurement as provided for in R.I. Gen. Laws §39-1-27.8, with the common purpose of meeting electrical and natural gas energy needs in Rhode Island in a manner that is optimally cost-effective, reliable, prudent, and environmentally responsible.[3]

B. In order to adhere to the principles set forth in R.I. Gen. Laws §39-1-27.7, and to meet Rhode Island's energy system needs in a least cost manner, the SRP Standards set forth guidelines for the incorporation of energy efficiency, distributed generation, demand response, and other energy technologies (collectively referred to as "non-wires alternatives" or NWA) into distribution company distribution planning. These guidelines seek to enable the deployment of cost-effective NWAs to achieve state policy goals, optimize grid performance, enhance reliability and resiliency, and encourage optimal investment by the distribution company.

C. SRP should be integrated with the distribution company's distribution planning process and be designed, where possible, to complement the objectives of Rhode Island's energy efficiency; renewable energy; and clean energy programs, and describe its interaction with them, including, but not limited to, the programs described in Section 1.2.A.ii. SRP should also be coordinated, where possible, with other applicable energy procurement, planning, and investment programs, including, but not limited to, Standard Offer Supply Procurement and the Infrastructure, Safety, and Reliability Plan.

2.2. Definitions

A. In order to fulfill the intent of the statute, SRP is interpreted to mean an ongoing distribution company practice to maximize the prudent, reliable, and environmentally responsible use of NWAs to meet electric distribution system needs and optimize grid performance, subject to a system whereby wires solutions and NWA solutions can be properly compared for both benefits and costs. NWA, including partial NWA, may be procured to meet distribution system needs of both load and generation.

B. NWAs may be utilized through various approaches to advance the goals of SRP and optimize grid performance as described in 2.1.B. These approaches may include, but are not limited to:

i. strategic promotion of customer-side NWA through investment or outreach by

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[3] R.I. Gen. Laws §39-1-27.7 specifies that standards and guidelines for System Reliability Procurement may include, but not be limited to: (i) procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in R.I. Gen. Laws §39-26; (ii) distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost- effective, with measurable, net system benefits; (iii) demand response, including, but not limited to, distributed generation, back-up generation, and on-demand usage reduction, which shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE") and/or are designed to provide local system reliability benefits through load control or using on-site generating capability.

the distribution company or a third party,

a. customer-side NWAs may include, but are not limited to:

(1) Least Cost Procurement energy efficiency baseline services,

(2) peak demand and geographically-focused supplemental energy efficiency strategies,

(3) distributed generation[4] generally, including combined heat and power and renewable energy resources,[5]

(4) demand response,

(5) direct load control,

(6) energy storage,

(7) electric vehicles,

(8) controllable or dispatchable electric heat or cooling,

(9) alternative metering and tariff options, including time-varying rates;

ii. distribution company investment in grid-side tools and technologies,

a. grid-wide NWAs may include, but are not limited to:

(1) energy storage,

(2) voltage management

(3) communications systems

(4) grid-optimization technologies[6]

(5) generation to provide, or in support of, any or all of B(ii)(1)-(4), consistent with Rhode Island General Laws;

iii. Combinations of NWAs (both customer-side and grid-side) and combinations of NWAs with traditional infrastructure investments.

C. Electric Distribution System Needs

i. Electric distribution system needs shall include, but are not limited to: system capacity (normal and emergency), voltage performance, reliability performance, protection coordination, fault current management, reactive power compensation, asset condition assessment, distributed generation constraints, and operational considerations. Note that not all system needs can be addressed by NWAs.

D. Optimization of Grid Performance

i. Optimizing grid performance refers to activities undertaken to improve the performance and efficiency of the electric distribution system by the distribution

[4] In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

[5] The term is defined in the Renewable Energy Standard, R.I. Gen. Laws § 39-26-5; http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26/39-26-5.HTM.

[6] "Grid-facing" investments may include technologies that automate grid operations and allow the distribution company to monitor and control grid conditions in near real time. (Source: MA DPU Docket 12-76-A, pg. 2)

company. Performance improvements can include enhanced reliability, peak load reduction, and increased capacity utilization for more efficient use of assets. More efficient delivery of electricity can include optimization of operations and reduced system losses. Costs and data requirements associated with these optimization activities should be considered.

ii. In the longer term, optimizing grid performance can include a response to anticipated changes to the distribution system and the associated planning process.

E. Prudency

i. Prudent planning under SRP will be assessed by:

a. risks associated with each alternative (ability to obtain licensing and permitting, significant risks of stranded investment, the potential risk reduction of a more incremental approach, sensitivity of alternatives to differences in load forecasts, and emergence of new technologies);

b. potential for synergy savings based on alternatives that address multiple needs;

c. implementation issues; and

d. customer responsiveness and ability to potentially modify usage at certain times and seasons.

F. Reliability

i. Reliability will be assessed by the following solutions:

a. ability to meet the identified system needs;

b. review of anticipated reliability as compared to alternatives;

c. operational complexity and flexibility; and

d. resiliency of the system.

G. Environmental Responsibility:

i. Environmental responsibility will be assessed by the manner in which the solution advances the goals and objectives of the State Energy Plan and other environmental policies. Considerations of environmental responsibility may include impacts on greenhouse gas emissions, criteria air pollution, land use, water, and other resources.

H. Cost-Effectiveness

i. Cost-effectiveness will be assessed by a comparison of costs and benefits as described in Section 2.3.F.

2.3. Assessment of Applicability of NWAs (SRP Planning)

A. Identified electric distribution system needs that meet the following criteria will be evaluated for potential NWAs that could reduce, avoid, or defer a transmission and distribution (T&D) wires solution over an identified time period.

i. The need is not based on asset condition.

ii. The wires solution, based on engineering judgment, will likely cost more than approximately $1 million; the cost floors may vary across different project types and time frames.

iii. If load reductions are necessary, then they are expected to be less than twenty

iv. (20) percent of the relevant peak load in the area, or sub-area in the event of a partial solution, of the defined need.

v. The start of wires alternative construction is at least thirty (30) months in the future.

vi. At its discretion, the distribution company may consider and, if appropriate, propose a project that does not pass one or more of these criteria if it has reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

B. If the distribution company determines that an NWA cannot defer the entire T&D project, the distribution company is encouraged to examine the application of NWAs to avoid or defer part of the overall scope of the project. This shall be referred to as 'partial' or 'hybrid' NWA. The distribution company will review reduction of the discrete portions of the entire T&D plan. Examples include: 1) reducing two new feeders to one new feeder; and 2) reducing a new proposed fully build station (2 power transformers, 8 feeders) to a partial station (1 power transformer, 4 new feeders).[7]

C. To further incorporate NWAs into the distribution company's distribution planning process, the distribution company may investigate the application of NWAs to reduce or manage load in areas, including, but not limited to, highly utilized distribution systems; where construction is physically constrained; and where demand growth is anticipated, to prolong the useful lifetime of existing systems. It is understood that an economic analysis framework for this type of NWA would need to be developed. With wider penetration, load-reduction NWAs are expected to generally defer or reduce infrastructure investment in a similar manner to EE efforts.

D. A more detailed version of these criteria may be developed by the distribution company and shared with the Council and other stakeholders.

E. Feasible NWAs will be compared to traditional solutions based on reliability, prudency, environmental responsibility, and the comparison of costs and benefits as defined below.[8]

F. Comparison of Benefits and Costs

i. The analysis of costs and benefits for each solution shall include a full assessment of costs and benefits of the various technologies; measures; and/or strategies included in the NWA as guided, where applicable, by the cost-effectiveness test outlined in Section 1 of these Standards. The following financial analysis should be conducted for each solution where an NWA is a viable option:

a. a calculation of the net-present-value benefit of deferring the traditional alternative over a set time period or eliminating the traditional alternative

[7] It is understood that reduction in the size of equipment (wire, transformers, etc.) offers little to no cost reduction to enable an economic NWA due to the discrete sizing of these components, and the distribution company is not expected to pursue such analysis.

[8] It is recognized that individual attributes can be compared to each other, but the ability to compare all the attributes together may not be able to be done at this time and may be the subject of other proceedings.

entirely as applicable;

b. a calculation of the net-present-value cost of the NWA over the same time period as the net-present-value calculation in (a);

c. a cost-benefit analysis, which shall consist of a comparison of (a.) and (b.) plus any other estimated benefits,

(1) other estimated benefits[9] shall include, but are not limited to: avoided capacity costs; avoided energy costs; avoided transmission costs; avoided ancillary service costs; market price suppression effect; improved reliability; revenues from grid resources; avoided greenhouse gas emissions; other environmental externalities; avoided environmental compliance costs; economic development benefits; and any site-specific, or option-specific benefits or costs directly attributable to the location of the project or the proposed alternatives, provided, however, that these benefits have not already been counted in the justification of any other underlying program (e.g. the Energy Efficiency Procurement Plan, the Renewable Energy Growth Program, the Net Metering Program, the Long-Term Contracting for Renewable Energy Standard, etc.) to avoid double- counting of benefits;

(2) recognizing that quantification methods for some benefits are not yet defined, and may need further research, where benefits cannot be reasonably quantified, a qualitative impact analysis or description of potential benefits should be included.

ii. Where there is no wires solution yet identified consistent with Section 2.3.C, a traditional benefit/cost analysis (consistent with this section) for the NWA should be done, and if it is greater than 1.0, the NWA can be recommended for approval.

2.4. Three-Year System Reliability Procurement Plan

A. The distribution company System Reliability Procurement Plan (SRP Plan) submitted on September 1, 2017, and triennially thereafter on September 1, shall describe general planning principles and potential areas of focus for SRP for the three years of implementation, beginning with January 1 of the following year. Such SRP Plans shall include, but are not limited to:

i. proposed evolutions to definitions, identification, and assessment of non-wires alternatives, which may include, but are not limited to:

a. observations and lessons learned from the most recent three-year period,

b. trends in distributed energy resource technology and analytics, either grid-side or customer-side, that may influence NWA planning over the three-year period;

ii. anticipated scope of NWA deployment in the coming three-year period,

a. in-progress NWA projects projected to continue and a high-level timeline,

[9] It is expected that site-specific avoided distribution costs and reduced operations and maintenance costs would be captured in the calculation of the net present value benefit of deferring or avoiding the traditional alternative.

b. projected areas of focus [10] for distribution planning review that may result in the identification of new NWA projects;

iii. description of how the SRP Plan complements the objectives of Rhode Island's energy efficiency, renewable energy, and clean energy programs listed in 2.1.C; and

iv. proposed shareholder incentive framework.

2.5. <u>Annual System Reliability Procurement Report</u>

A. The distribution company shall prepare and file a supplemental filing on November 1, 2017, and annually thereafter on November 1, containing details of implementation of the SRP Plan for the next program year (SRP Report). Such reports will include, but are not limited to:

i. identification and NWA-viability determination of needs that passed the initial screening in Section 2.3;

ii. identification of needs where an NWA project was selected as a solution including:

a. a summary of the comparative analysis following the criteria outlined in Section 2.3 above, and

b. characterization of the transmission or distribution need including:

(1) the magnitude (daily and annual load shape curves, voltage improvement, etc.); if applicable, the projected year and season by which a solution is needed; and other relevant timing issues;

(2) description of the traditional wires solution and how it is impacted by the NWA; [11]

(3) description of the sensitivity of the need and T&D investment to load forecast assumptions;

iii. description of how the NWA projects complement the objectives of Rhode Island's energy efficiency, renewable energy, and clean energy programs listed in 2.1.C;

iv. implementation plans for the newly selected NWA projects and any previously approved projects being proposed for continuation, which should include:

a. a description of the NWA solution, including technology; customer engagement; cost (capital and operations and maintenance), net present value, and timing,

b. the ability of affected customers to participate in the proposed project,

c. a description and results of any competitive bid (request for proposals) processes that were conducted to inform the description in 2.5.A.iv.a,

d. the proposed NWA investment scenario(s),

[10] It is not anticipated that this will include project specifics, which are dependent on needs and screening; those are expected in annual SRP Reports. In the absence of project specifics or budgets, this section is intended to give a picture of the expected size and scope of NWA efforts during the three-year period and a sense of whether it is expected to grow relative to current activities.

[11] Description should include technology proposed, net present value, costs (capital and O&M), revenue requirements, and timeline for the upgrade

e. the proposed technology ownership and contracting considerations or options,

f. the proposed evaluation plans;

v. funding plans for the selected NWA projects and any previously approved projects being proposed for continuation; the distribution company may propose to utilize funding from the following sources for system reliability investments:

a. capital funds that would otherwise be applied towards traditional wires based alternatives, where the costs for the NWA are properly capitalized under generally accepted accounting principles and can be properly placed in rate base for recovery in rates along with other ordinary infrastructure investments,

b. existing distribution company EE investments, as required in Chapter 1 of these Standards, and the resulting Annual Plans,

c. additional energy efficiency funds to the extent that the energy efficiency-related NWA can be shown to pass the cost-benefit test, as outlined in Chapter 1 of these Standards, and such additional funding is approved,

d. utility operating expenses, to the extent that recovery of such funding is explicitly allowed,

e. identification of customer contribution or third-party investment that may be part of a NWA based on benefits that are expected to accrue to the specific customers or third parties,

f. any other funding sources that might be required and available to complete the NWA;

vi. status of any previously selected and approved projects and pilots;

vii. identification of any methodological or analytical tools to be developed in the year;

viii. total SRP Plan budget, including administrative and evaluation costs;

ix. proposed shareholder incentive.

B. To the extent the implementation of a NWA may contribute to an outage event that is beyond the control of the distribution company, the distribution company may apply to the PUC for an exclusion of such event in the determination of Service Quality performance.

2.6. <u>SRP Performance Incentive Plan</u>

A. The distribution company shall have an opportunity to earn a shareholder incentive that is dependent on its performance in implementing the approved SRP Plan.

B. The distribution company, in consultation with the Council, will propose in its SRP Plan a PI proposal that is designed to promote superior distribution company performance in cost-effectively and efficiently delivering least cost and reliable non-wires alternatives projects.

C. The PI should be structured to reward program performance that makes significant progress in securing least cost and reliable non-wires alternatives projects while, at the same time, ensuring that those resources are secured as efficiently as possible.

D. The PI may provide incentives for other objectives that are consistent with the goals, including, but not limited to, resiliency; connectivity; and operability.

E. The PI should be sufficient to provide a high level of motivation for excellent distribution company performance annually and over the three-year period of the SRP Plan, but structured so that customers receive most of the benefit from SRP implementation.

F. The PI shall state clearly each specific objective it is designed to direct the distribution company to achieve and the reason it is needed to do so. The design of the PI shall be clear and focused, have clear metrics for determining performance, not duplicate incentives, and not provide multiple or different incentives for attaining the same objective.

Appendix 2 – Rhode Island Company Electric Service Projected Load Growth Rates

Rhode Island Projected Load Growth Rates

State	County	Town	Annual Growth Rates (%) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	5-year Average (%) 2019 to 2023	10-year Average (%) 2019 to 2028
RI			-0.1	-0.2	-0.2	-0.1	-0.1	0.1	0.1	0.1	0.0	-0.1	-0.1	0.0
	BRISTOL		-0.4	-0.4	-0.5	-0.3	-0.3	-0.1	0.0	0.0	-0.1	-0.2	-0.4	-0.2
	KENT		-0.3	-0.3	-0.4	-0.2	-0.2	0.0	0.0	0.1	-0.1	-0.2	-0.3	-0.2
	NEWPORT		-0.3	-0.4	-0.4	-0.2	-0.2	-0.1	0.0	0.0	-0.1	-0.2	-0.3	-0.2
	PROVIDENCE		-0.6	-0.6	-0.6	-0.4	-0.3	-0.2	-0.1	-0.1	-0.2	-0.3	-0.5	-0.3
	WASHINGTON		1.0	0.8	0.7	0.8	0.7	0.7	0.7	0.7	0.5	0.3	0.8	0.7
	WASHINGTON	Kenyon	-2.3	-2.2	-2.0	-1.7	-1.5	-1.3	-1.1	-0.9	-1.0	-1.0	-1.9	-1.5
	WASHINGTON	Narragansett	0.3	0.2	0.1	0.2	0.2	0.3	0.3	0.3	0.2	0.0	0.2	0.2
	WASHINGTON	Peace Dale	1.6	1.4	1.2	1.2	1.1	1.1	1.0	1.0	0.7	0.5	1.3	1.1

Rhode Island

2019 Electric Peak (MW) Forecast

Long-Term: 2019 to 2033

[Narragansett Electric Company]

December 2018

Rev. 2, 12/15//2018

Advanced Data & Analytics
Business Processes

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Rev. 2	12/15/2018	- add additional load curves
Rev. 1	12/04/2018	- correct Appendix B PV table
Rev. 0	11/01/2018	- ORIGINAL

General Notes:

- Input data through **August 2018**; Projections from 2019 forward;
- Economic data is from Moody's vintage **August 2018**.
- Energy Efficiency data is vintage **August 2018.**
- Distributed Generation data is vintage **August 2018.**
- Electric Vehicle data is vintage **August 2018**. **[NEW FOR 2018]**
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (1/2003 to 6/2018); internal unreconciled **preliminary** data (Jul. 2018 & Aug. 2018).
- Peak day & times in this report refer to those for the Company and not for ISO-NE peak.
- "Independent" refers to the zone's peak day/time.
- References to "zone" refers to the Company's service territory within the ISO-NE zonal designations; all data is National Grid's service territory within the zones.
- The term "Weather-Normal" and "Extreme" 90/10 ("1 in 10") and 95/5 ("1 in 20") weather are based on 20 year average.
- DR impacts are "added-back" to loads
- PV impacts are based on BEHIND THE METER installations
- 24 hour peak & typical day curves are new for 2018.

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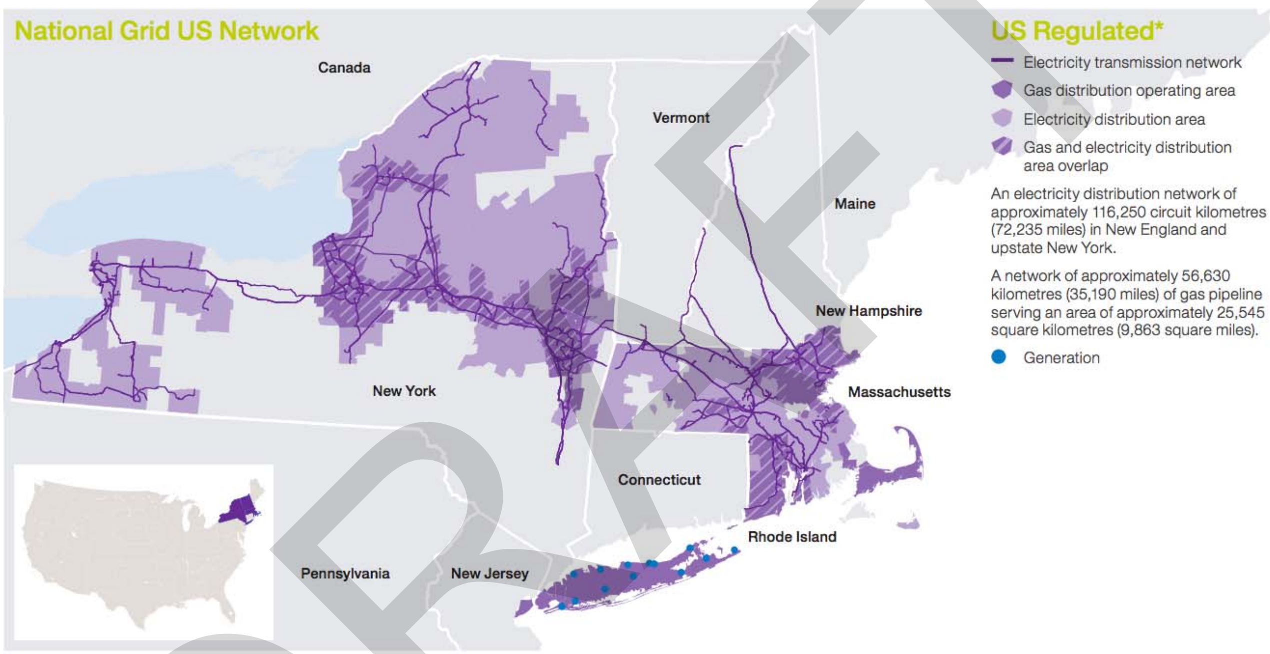
CONTENTS

Summary

National Grid's US electric system is comprised of four companies serving 3.4 million customers in Rhode Island, Massachusetts and Upstate New York. The four electric distribution companies are Narragansett Electric Company, serving 0.5 million customers in Rhode Island, Massachusetts Electric Company and Nantucket Electric Company, serving 1.3 million customers in Massachusetts and Niagara Mohawk Power Company, serving 1.6 million customers in upstate New York. Figure 1[1] shows the Company's service territory in the U.S..

Figure 1



*Access to electricity and gas transmission and distribution assets on property owned by others is controlled through various agreements.

Source: National Grid

Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electric infrastructure, enables timely procurement and installation of required facilities, and it provides system planning with information to prioritize and focus their efforts. In addition to these internal reliability and capital planning internal uses, the peak forecast is also used to support regulatory requirements with the state, federal, and other agencies.

Narragansett electric Company's (NECO) peak demand in Rhode Island in 2018 was 1,845[2], on Wednesday, August 29th at hour-ending 17. The 2018 peak was 7% below the NECO all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

[1] National Grid also serves gas customers in these same states which are also shown on this map.

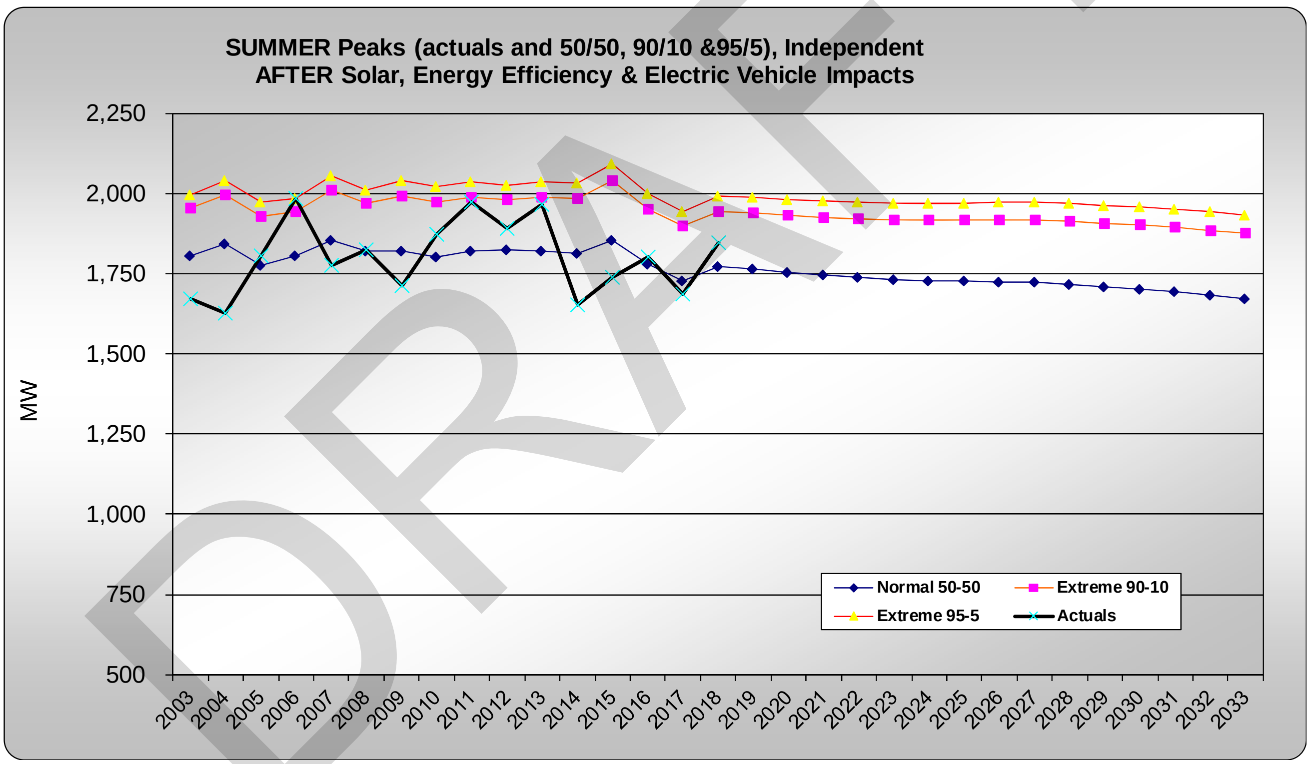
[2] Meter Data Service's system level PRELIMINARY peak and subject to change

This summer's peak weather was considered *warmer* than normal (50/50 or average). It could be considered about an 70/30 summer, or more than average, but less than the most extreme[3]. This year's peak is estimated to be 71 MW above the peak the company would have experienced under normal weather conditions. Thus, on a weather adjusted "normal" basis this year's peak was estimated to be 1,774 MW, an increase of 2.7% vs. last year's weather-adjusted 'normal' peak.

The forecast indicates that the overall service territory will experience negative growth of -0.4% annually over the next fifteen years, primarily due to the impacts of energy efficiency and solar PV offsetting any underlying economic growth. Electric vehicle impacts are not expected to overcome decreases due to the EE and PV.

Figure 2 shows this forecast graphically.

<u>Figure 2</u>



<u>Forecast Methodology</u>

National Grid in Rhode Island forecasts its peak MW demands for its service territory in the state.

[3] For planning purposes, network strategy uses a 90/10 for transmission planning and a 95/5 for distribution planning for weather extremes.

The overall approach to the peak forecast is to relate (or regress) peak MWs to energy growth and state economic factors (if appropriate). This method allows the peak MW forecasts to grow along with energy growth rates, however it also allows the peak to adjust to other economic influences in each area.

The model is developed based on a "reconstructed" model of past load. That is, claimed energy efficiency, known solar PV and EV are first added back to the historical data set before the model is run. Future projections are made based on the "reconstructed" data set, then future cumulative estimates of savings for the distributed energy resources (DERs) for energy efficiency, solar-PV and EV are taken out to arrive at the final forecast.

Post-model reductions were made to the initial forecast model for energy efficiency (EE), solar (DG), electric vehicles (EV) and increased for historical demand response (DR) impacts.

The results of this forecast are used as input into various system planning studies. The forecast is presented for all three weather scenarios. The transmission planning group uses the extreme-90/10 weather scenario for its planning purposes. For distribution planning, the degree of diversity is reduced and the variability of load is greater, so a 95/5 forecast is used.

Distributed Energy Resources (DERs)

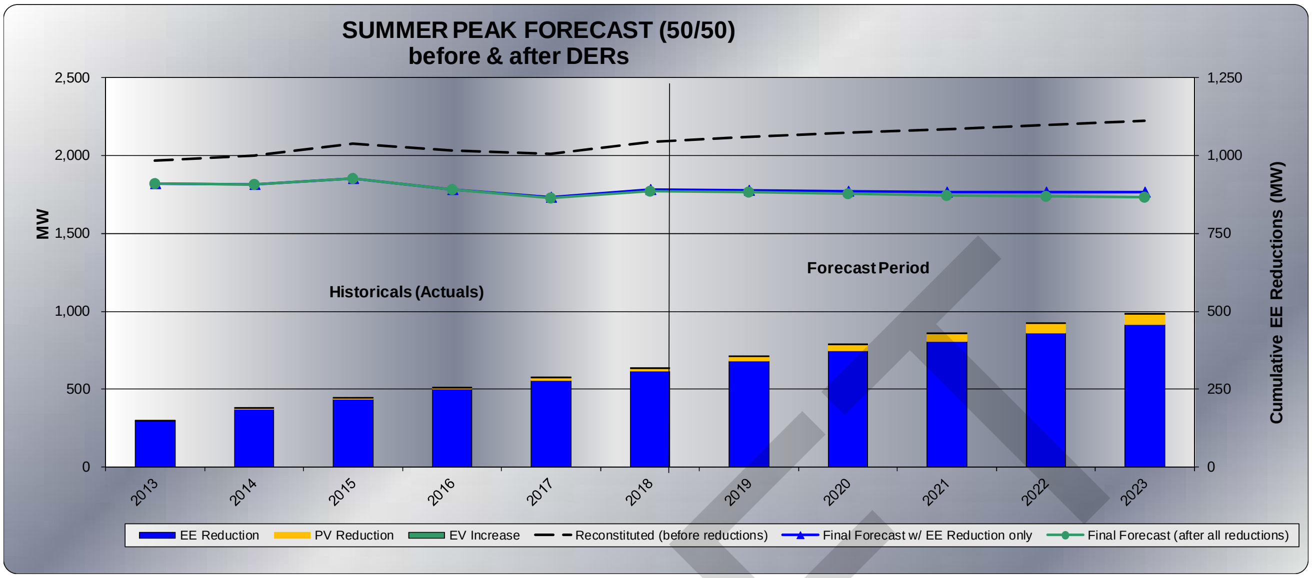
In New England there are a number of policies, programs and technologies that are impacting customer loads. These include, but are not limited to energy efficiency, distributed generation (specifically solar distributed generation), electric vehicles and demand response. These collectively are termed distributed energy resources because they impact the loads at the customer level, as opposed to traditional, centralized power supplies.

Energy Efficiency (EE)

National Grid has been running energy efficiency programs in its Rhode Island jurisdiction for a number of years and will continue to do so for the foreseeable future. In the short-term (one to three years) energy efficiency targets are based on approved company programs. Over the longer term the Company uses the ISO-NE projections for the state. The ISO-NE EE projections account for state policies, company programs and other market factors.

Figure 3 shows the expected loads and energy efficiency program reductions to NECO peaks by year. As of 2018, it is estimated that these EE programs have reduced loads by 308 MW than if there were no programs run. By 2033, it is expected that this reduction will grow to 646 MW or 27.0% of what load would have been had these programs not been implemented. Over the fifteen year planning horizon these reductions lower annual growth from 0.9% to -0.1% per year.

Figure 3



Distributed Generation (Solar – Behind-the-meter[4] PV)

There has been a rapid increase in the adoption of solar[5] throughout the state. The Company tracks historical PV and that becomes the basis of the historical values shown. The projection for the future is based on the Company's pro-rata share by load of PV in each zone that the ISO-NE shows in its annual load & capacity report[6]. The ISO-NE considers current PV and policy goals for the future. Since the Company does not have its own territory wide PV programs as it does with energy efficiency this approach ensures consistency with the statewide and area specific projections of the ISO. In the short-term (one to two years) the company reviews the quantity of applications already in the 'queue' to make sure the projections based on the share of ISO estimates are reasonable.

Figure 3 above shows the expected NECO loads and solar reductions to peaks by year. As of 2018, it is estimated that this technology may have already reduced system peak loads by 8 MW. By 2033 it is expected that these reductions may grow to 78 MW[7], or 3.3% of what load would have been had this technology not been installed. Over the fifteen year planning horizon these reductions lower annual growth from 0.9% to 0.7% per year.

[4] This discussion is limited to "Behind-the-(customer) meter PV which is that expected to reduce loads, and would not include those PV installations considered as 'supply' by the ISO-NE.
[5] The Company limits this discussion to the impacts of solar distributed generation because it is the single largest contributor and the fastest growing of all distributed generation technologies at this time.
[6] 2018 Capacity, Energy, Load & Transmission Report, a report by the New England Independent System Operator, Inc., "CELT", dated May 2018.
[7] These are Company system summer peak impacts; these are approximately 21% of connected PV MWs.

The prevalence of the EE and PV and their continued expansion clearly show how loads have been significantly lowered due to their success.

Electric Vehicles

Over the longer-term, the forecast results are further adjusted for the penetration of plug-in electric vehicles (PEVs). Electric vehicles of interest are those that "plug-in" to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in 'battery-only' electric vehicles" (BEVs). These two types are those that could have potential impacts on the electric network.

National Grid has developed estimates for several scenarios covering a mix of different levels of future adoption of PEVs. These scenarios generally range low to higher levels of adoption. These scenarios include:

- Annual Energy Outlook (AEO) Low: This scenario uses information from the Department of Energy's 2018 AEO8 report to determine a scenario for PEVs in National Grid's share of the state's in which its service territory spans, mainly Massachusetts, Rhode Island and New York. The "low" scenario is selected as AEO "Reference" case.

- Annual Energy Outlook (AEO) High: This scenario similarly uses information from 2018 AEO report. For the "high" scenario, the AEO "High Oil (price)" case was used. While this case is not a high PEV case per se, it does have the highest penetration of PEVs versus the other AEO cases.

- Percent of New Registrations: This scenario uses the historical adoption rate of "non plug-in hybrid electric vehicles" (NPHEVs) as a proxy for how the plug-in electric vehicle adoption might behave. This scenario is determined as a function of new PEV registrations each year as a percent of all new vehicle registrations[9]. NPHEVs have been in the market for over ten years and have a record of adoption over that time frame. This scenario assumes that PEVs, which have not until recently begun to be widely adopted in the marketplace, may behave similarly to that of NPHEVs. This scenario is considered the **Base Case**.

- Zero Emissions Vehicles (ZEVs) target: This scenario assumes that PEV adoption meets the ZEV targets of about 45,000[10] in Rhode Island by the year 2025. National

[8] 2018 Annual Energy Outlook (AEO) report, U.S. Energy Information Administration (EIA), Department of Energy (DOE).

[9] National Grid has a contract with R.L. POLK and Company (IHS Automotive), a Company which is a leader in compiling electric vehicle registration information. It also contracts with Moody's Analytics, a leader in compiling economic and demographic information including motor vehicle registrations and future projections.

[10] Based on share of population for RI vs. total multi-state ZEV targets of 3.3 million by 2025.

Grid is assumed to garner a share of those goals as a function of its current share of PEVs in its service territory as a percent PEVs in the entire state. Current levels of PEVs are ramped up between now and the year 2025 to achieve those shares.

In Rhode Island, basecase PEV adoption may result in increased sales of about 3 MW, or 0.1% by 2033. PEV volumes grow to over 9,500 over the fifteen year planning horizon, or by 2033, for the Base Case. **Figure 3** above includes the EV projections.

Explicit impacts to system peaks have been made for these energy efficiency, solar PV and electric vehicle projections.

<u>Demand Response</u>

Demand Response (or "DR") are programs that actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These are in contrast to the more passive energy efficiency savings discussed above that provide savings throughout the year. The DR programs enable utilities and operating areas, such as the New England Independent System Operator (ISO-NE) to take action in response to a system reliability concern or economic (pricing) signal. During these events customers can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

The ISO-NE has been implementing these type programs for a number of years now and for the purposes of this report are referred to as "wholesale DR". These programs have been activated several times over the last decade (they have not been activated since 2016). The Company's policy has been to add-back reductions from these call-outs to its reported system peak numbers. This is because the Company is not in control of the call-out days nor times and thus there is no guarantee that these ISO –NE call-outs would be at the times of Company peaks. Therefore, the Company recognizes their existence, but must plan in the event that they are not called.

Table 1 shows the estimated reductions* for the historical call-outs on the peak days.

Table 1

DATE	HOUR	NEMA	SEMA	WCMA	RI
11-Aug-2016	16	4.9	5.4	16.7	10.4
11-Aug-2016	17	4.9	4.9	17.1	10.0
11-Aug-2016	18	4.5	3.7	15.9	8.8
11-Aug-2016	19	3.7	3.5	15.5	8.5
19-Jul-2013	14	4.6	6.0	13.5	9.8
19-Jul-2013	15	5.2	6.0	14.0	11.7
19-Jul-2013	16	4.4	5.1	13.5	8.8
19-Jul-2013	17	4.4	4.2	12.3	9.8
19-Jul-2013	18	4.2	3.2	12.3	7.8
19-Jul-2013	19	4.0	3.7	10.1	5.9
19-Jul-2013	20	3.8	3.7	8.4	5.9
22-Jul-2011	13	9.3	12.9	16.3	24.8
22-Jul-2011	14	13.3	18.3	23.2	35.2
22-Jul-2011	15	15.1	20.7	26.3	39.9
22-Jul-2011	16	14.8	20.4	25.8	39.2
22-Jul-2011	17	14.2	19.6	24.8	37.7
22-Jul-2011	18	13.1	18.0	22.8	34.7
02-Aug-2006	13	1.0	7.0	13.5	36.1
02-Aug-2006	14	1.0	7.0	13.5	36.1
02-Aug-2006	15	1.0	7.0	13.5	36.1
02-Aug-2006	16	1.0	7.0	13.5	36.1
02-Aug-2006	17	1.0	7.0	13.5	36.1
02-Aug-2006	18	1.0	7.0	13.5	36.1
01-Aug-2006	16	0.2	1.1	2.2	5.8
01-Aug-2006	17	0.2	1.1	2.2	5.8
01-Aug-2006	18	0.2	1.1	2.2	5.8
01-Aug-2006	19	0.2	1.1	2.2	5.8
01-Aug-2006	20	0.2	1.1	2.2	5.8

*It should be noted that the absolute MW do not always translate into one-to-one reductions to the peak depending on the timing of DR call-outs and pre-DR metered loads.

The Company recently began a DR program at the 'retail', or customer level. In contrast to the wholesale level DR programs implemented by the ISO-NE, these programs would be activated by the Company. Committed amounts for the 2018 program in RI were about 10 MWs. The program was called on a number of days this summer (July 3rd and 5th, August 6th, 7th 28th and 29th and September 5th). The evaluated results from these call-outs will be analyzed and a decision on how to handle these retail DRs during the next planning cycle will be made. An important consideration will be the achieved vs. committed reductions, the timing of call-out days vs. actual peak days and long-term commitments to these programs. Since planning decisions for reliability purposes are based on achievable, longer term reductions, these are important considerations for network strategy & planning.

Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New England service territory and used to weather-adjust peak demands. The relevant weather station for Rhode Island is Providence.

The weather variables used in the model include heating degree days for the colder winter months and temperature – humidity indexes (THIs)[11] for the warmer summer months. These weather variables are correlated to the actual days that each peak occurs in each season over the historical period. Summer THI uses a weighted three day index (WTHI)[12] to capture the effects of prolonged heat waves that drive summer peaks.

Weather adjusted peaks are derived for "normal (50/50)" average weather, "90/10 (1 in 10)" extreme weather and "95/5 (1 in 20)" extreme weather. Extreme weather scenarios are determined using a "probabilistic" approach that employs "Z-values" and standard deviations (i.e. the more variable the weather has been on peak days over the historical period, the higher the 90/10 and 95/5 levels will be versus the average).

- Normal "50/50" weather is the average weather on the past 20 seasonal peak days.
- Extreme "90/10" weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten year period.
- Extreme "95/5" weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty year period.

These "normals" and "extremes" are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Peak Day 24 Hourly Curves (before and after DERs)

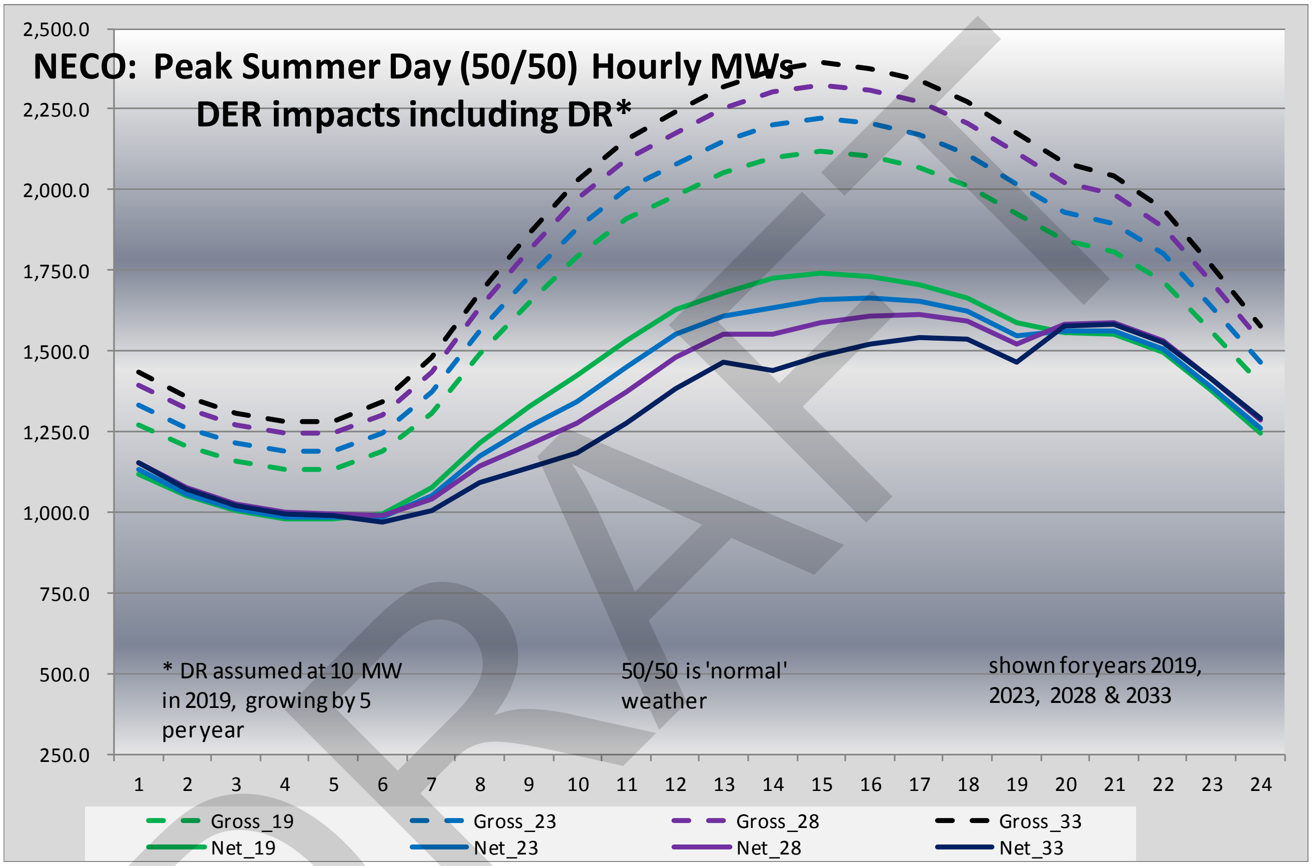
There are several initiatives proposed under the state's Power Sector Transformation (PST) proceeding that may impact customer loads, DERs and network planning. The company is aware of these and will monitor the progress of this proceeding and make appropriate changes to this forecast as appropriate. One of the initial changes to this annual planning report is the inclusion of estimated impacts due to DERs on an hourly basis on the peak day. This will allow the Company to look beyond the traditional approach of predicting the 'single' highest summer system peak each year. The process now looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as

[11] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.
[12] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior

more DERs are added. For example, as more and more solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off.

Figure 4 shows the impact of the “24 hour” PEAK day perspective for selected peak summer days over the planning horizon.

Figure 4

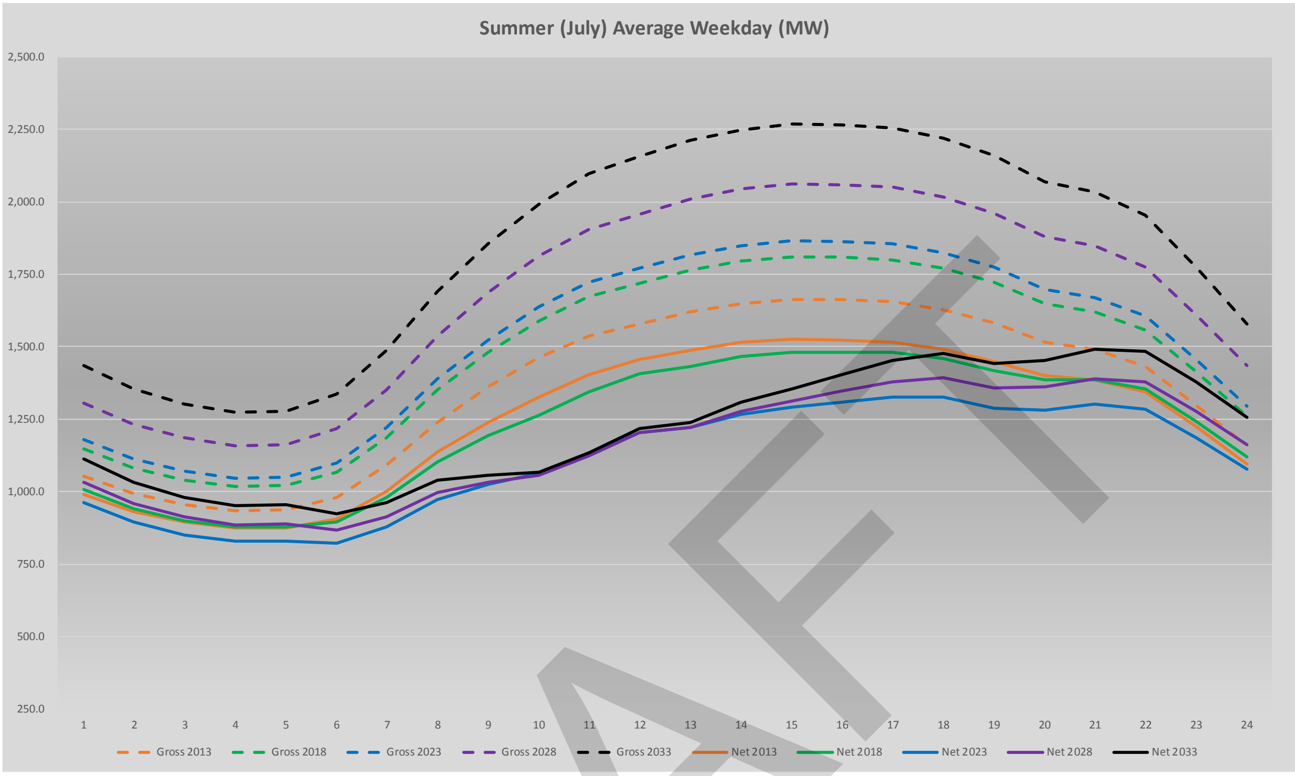


In this figure, it clearly shows how the expected DERs not only lower the loads, but also shift the hour of the peaks. In this figure, the hour of the peak begins at hour-ending 17 in year 2019 but shifts to hour-ending 21 by the year 2033. This shows how PV and DR can shift the peak away from the typical afternoon hours to late evening. EV charging can further add to evening and possibly even later peaks.

“Gross” refers to before any DER impacts and “Net’ refers to load after DER. The numbers refer to years 2019, 2023, 2028 and 2033, respectively.

Figure 5 shows the impact of the “24 hour” AVERAGE summer weekday perspective for selected peak summer days over the planning horizon.

Figure 5



In this figure, it shows similar hourly patterns to the peak days, however at lesser MW levels because this displays an average summer day vs. the less frequent peak weather producing days. Also, on an average day, it is not expected that DR would be implemented.

Appendix D contains additional load shapes for other days types including winter and shoulder month average weekdays and summer, winter and shoulder month weekend days. These show the varying seasonal patterns as well as the lower load shoulder months which for the most part show baseloaded energy use with minimal impacts of cooling or heating. Weekend loads patterns also provide a view on lower loads due to the lesser impacts of weekday business use.

[These values and graphs are shown for ***informational purposes only*** at this time and have **not** been explicitly included in the peak forecasts in the rest of this document].

Appendix A: Forecast Details

NARRAGANSETT ELECTRIC COMPANY (NECO)

NECO
SUMMER (Independent) Peaks

AFTER Solar, Energy Efficiency & Electric Vehicle Impacts

	Actuals		Normal 50-50		Extreme 90-10		Extreme 95-5		WTHI
YEAR	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	ACTUAL
2003	1,670		1,806		1,954		1,996		80.1
2004	1,628	-2.5%	1,842	2.0%	1,997	2.2%	2,041	2.3%	78.5
2005	1,805	10.8%	1,775	-3.6%	1,930	-3.4%	1,973	-3.3%	83.1
2006	1,985	10.0%	1,806	1.8%	1,945	0.8%	1,983	0.5%	85.9
2007	1,777	-10.5%	1,855	2.7%	2,011	3.4%	2,055	3.6%	80.9
2008	1,824	2.6%	1,820	-1.9%	1,969	-2.1%	2,011	-2.1%	82.9
2009	1,713	-6.1%	1,820	0.0%	1,993	1.2%	2,041	1.5%	80.3
2010	1,872	9.3%	1,802	-1.0%	1,973	-1.0%	2,021	-1.0%	84.5
2011	1,974	5.5%	1,821	1.1%	1,990	0.9%	2,038	0.8%	84.8
2012	1,892	-4.2%	1,826	0.3%	1,981	-0.4%	2,026	-0.6%	83.5
2013	1,965	3.9%	1,821	-0.2%	1,990	0.4%	2,038	0.6%	84.7
2014	1,653	-15.9%	1,814	-0.4%	1,985	-0.2%	2,034	-0.2%	80.4
2015	1,738	5.1%	1,854	2.2%	2,040	2.8%	2,093	2.9%	80.4
2016	1,803	3.8%	1,782	-3.9%	1,951	-4.4%	2,000	-4.5%	82.6
2017	1,688	-6.4%	1,727	-3.1%	1,897	-2.8%	1,946	-2.7%	81.7
2018	1,845	9.3%	1,774	2.7%	1,945	2.5%	1,994	2.5%	83.4
2019	-	-	1,764	-0.5%	1,939	-0.3%	1,989	-0.3%	-
2020	-	-	1,755	-0.5%	1,932	-0.3%	1,983	-0.3%	-
2021	-	-	1,745	-0.6%	1,925	-0.4%	1,976	-0.3%	-
2022	-	-	1,738	-0.4%	1,921	-0.2%	1,973	-0.1%	-
2023	-	-	1,732	-0.3%	1,918	-0.2%	1,970	-0.1%	-
2024	-	-	1,729	-0.2%	1,917	-0.1%	1,970	0.0%	-
2025	-	-	1,727	-0.1%	1,917	0.0%	1,971	0.1%	-
2026	-	-	1,726	-0.1%	1,918	0.1%	1,973	0.1%	-
2027	-	-	1,722	-0.2%	1,917	-0.1%	1,972	-0.1%	-
2028	-	-	1,717	-0.3%	1,913	-0.2%	1,969	-0.2%	-
2029	-	-	1,710	-0.4%	1,908	-0.3%	1,964	-0.2%	-
2030	-	-	1,703	-0.4%	1,902	-0.3%	1,959	-0.3%	-
2031	-	-	1,694	-0.5%	1,894	-0.4%	1,952	-0.4%	-
2032	-	-	1,684	-0.6%	1,886	-0.5%	1,943	-0.4%	-
2033	-	-	1,673	-0.7%	1,876	-0.5%	1,934	-0.5%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Compound Avg. 15 yr ('03 to '18)	-0.1%	0.0%	0.0%
Compound Avg. 10 yr ('08 to '18)	-0.3%	-0.1%	-0.1%
Compound Avg. 5 yr ('13 to '18)	-0.5%	-0.5%	-0.4%
Compound Avg. 5 yr ('18 to '23)	-0.5%	-0.3%	-0.2%
Compound Avg. 10 yr ('18 to '28)	-0.3%	-0.2%	-0.1%
Compound Avg. 15 yr ('18 to '33)	-0.4%	-0.2%	-0.2%

WTHI

NORMAL	82.3
EXTREME 90/ 10	85.1
EXTREME 95/ 5	85.8

NECO	SUMMER Independent 50/50 Peaks (MW) (before & after DERs)										
	------------- SYSTEM PEAK (50/50) -------------					------------ DER IMPACTS ----------					
Calendar Year	Reconstituted (before reductions)	Final Forecast w/ EE Reduction only	Final Forecast w/ PV Reduction only	Final Forecast w/ EV Reduction only	Final Forecast (after all reductions)	EE Reduction Forecast	PV Reduction Forecast	EV Increase Forecast	EE % of 'Reconstituted' Deliveries	PV % of 'Reconstituted' Deliveries	EV % of 'Reconstituted' Deliveries
2003	1,816	1,806	1,816	1,816	**1,806**	9	0	0.0	0.5%	0.0%	0.00%
2004	1,863	1,842	1,863	1,863	**1,842**	21	0	0.0	1.1%	0.0%	0.00%
2005	1,806	1,775	1,806	1,806	**1,775**	30	0	0.0	1.7%	0.0%	0.00%
2006	1,847	1,806	1,847	1,847	**1,806**	41	0	0.0	2.2%	0.0%	0.00%
2007	1,906	1,855	1,906	1,906	**1,855**	51	0	0.0	2.7%	0.0%	0.00%
2008	1,881	1,820	1,881	1,881	**1,820**	61	0	0.0	3.3%	0.0%	0.00%
2009	1,897	1,820	1,897	1,897	**1,820**	77	0	0.0	4.0%	0.0%	0.00%
2010	1,891	1,802	1,891	1,891	**1,802**	89	0	0.0	4.7%	0.0%	0.00%
2011	1,923	1,821	1,923	1,923	**1,821**	102	0	0.0	5.3%	0.0%	0.00%
2012	1,947	1,826	1,947	1,947	**1,826**	121	0	0.0	6.2%	0.0%	0.00%
2013	1,970	1,822	1,969	1,970	**1,821**	148	1	0.0	7.5%	0.0%	0.00%
2014	2,002	1,815	2,001	2,002	**1,814**	187	1	0.0	9.3%	0.0%	0.00%
2015	2,076	1,856	2,074	2,076	**1,854**	220	1	0.1	10.6%	0.1%	0.01%
2016	2,035	1,785	2,032	2,036	**1,782**	250	4	0.1	12.3%	0.2%	0.01%
2017	2,013	1,733	2,007	2,013	**1,727**	280	7	0.2	13.9%	0.3%	0.01%
2018	2,089	1,782	2,081	2,089	**1,774**	308	8	0.3	14.7%	0.4%	0.02%
2019	2,119	1,778	2,106	2,120	**1,764**	342	14	0.5	16.1%	0.6%	0.02%
2020	2,147	1,773	2,128	2,148	**1,755**	374	19	0.7	17.4%	0.9%	0.03%
2021	2,171	1,768	2,148	2,172	**1,745**	404	24	1.0	18.6%	1.1%	0.04%
2022	2,197	1,766	2,169	2,199	**1,738**	432	29	1.2	19.6%	1.3%	0.05%
2023	2,222	1,764	2,189	2,223	**1,732**	458	33	1.4	20.6%	1.5%	0.06%
2024	2,246	1,765	2,208	2,248	**1,729**	481	38	1.6	21.4%	1.7%	0.07%
2025	2,269	1,768	2,227	2,271	**1,727**	502	43	1.8	22.1%	1.9%	0.08%
2026	2,291	1,771	2,243	2,293	**1,726**	520	47	2.0	22.7%	2.1%	0.09%
2027	2,309	1,772	2,258	2,312	**1,722**	538	52	2.2	23.3%	2.2%	0.10%
2028	2,326	1,771	2,270	2,329	**1,717**	556	56	2.4	23.9%	2.4%	0.10%
2029	2,342	1,768	2,281	2,344	**1,710**	574	60	2.5	24.5%	2.6%	0.11%
2030	2,357	1,765	2,292	2,359	**1,703**	592	65	2.5	25.1%	2.8%	0.11%
2031	2,370	1,761	2,301	2,373	**1,694**	610	69	2.5	25.7%	2.9%	0.11%
2032	2,383	1,755	2,309	2,385	**1,684**	628	74	2.6	26.3%	3.1%	0.11%
2033	2,394	1,748	2,316	2,396	**1,673**	646	78	2.6	27.0%	3.3%	0.11%

Compound Avg. 15 yr ('03	0.9%	-0.1%	0.9%	0.9%	**-0.1%**
Compound Avg. 10 yr ('08	1.1%	-0.2%	1.0%	1.1%	**-0.3%**
Compound Avg. 5 yr ('13	1.2%	-0.4%	1.1%	1.2%	**-0.5%**
Compound Avg. 5 yr ('18	1.2%	-0.2%	1.0%	1.3%	**-0.5%**
Compound Avg. 10 yr ('18	1.1%	-0.1%	0.9%	1.1%	**-0.3%**
Compound Avg. 15 yr ('18	0.9%	-0.1%	0.7%	0.9%	**-0.4%**

NECO

WINTER (Independent) Peaks — **AFTER Energy Efficiency & Electric Vehicle Impacts**

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2003	1,389		1,316		1,375		1,391		55.7
2004	1,394	0.4%	1,426	8.3%	1,477	7.5%	1,492	7.2%	36.7
2005	1,329	-4.6%	1,322	-7.3%	1,369	-7.3%	1,383	-7.3%	45.0
2006	1,329	0.0%	1,315	-0.5%	1,363	-0.5%	1,376	-0.5%	45.5
2007	1,352	1.7%	1,325	0.8%	1,372	0.7%	1,385	0.6%	44.8
2008	1,305	-3.5%	1,314	-0.8%	1,365	-0.5%	1,379	-0.4%	40.0
2009	1,294	-0.8%	1,326	0.9%	1,379	1.0%	1,394	1.1%	35.0
2010	1,315	1.6%	1,263	-4.8%	1,320	-4.3%	1,336	-4.2%	53.1
2011	1,243	-5.5%	1,248	-1.1%	1,302	-1.4%	1,317	-1.4%	41.6
2012	1,320	6.2%	1,287	3.1%	1,341	3.0%	1,356	3.0%	51.9
2013	1,328	0.7%	1,321	2.6%	1,375	2.6%	1,391	2.6%	43.9
2014	1,275	-4.0%	1,227	-7.1%	1,284	-6.6%	1,301	-6.5%	52.2
2015	1,223	-4.1%	1,198	-2.3%	1,248	-2.8%	1,263	-2.9%	55.0
2016	1,239	1.3%	1,275	6.4%	1,336	7.0%	1,353	7.2%	35.9
2017	1,277		1,202	-5.7%	1,279	-4.3%	1,300	-3.9%	53.8
2018	-		1,186	-1.4%	1,256	-1.7%	1,276	-1.8%	-
2019	-		1,169	-1.4%	1,243	-1.1%	1,264	-1.0%	-
2020	-		1,147	-1.9%	1,222	-1.6%	1,244	-1.6%	-
2021	-		1,129	-1.6%	1,206	-1.3%	1,228	-1.2%	-
2022	-		1,125	-0.4%	1,206	0.0%	1,229	0.1%	-
2023	-		1,117	-0.7%	1,201	-0.4%	1,225	-0.3%	-
2024	-		1,114	-0.3%	1,202	0.0%	1,227	0.1%	-
2025	-		1,112	-0.1%	1,203	0.1%	1,229	0.2%	-
2026	-		1,112	0.0%	1,206	0.2%	1,232	0.3%	-
2027	-		1,117	0.5%	1,215	0.8%	1,243	0.9%	-
2028	-		1,128	1.0%	1,231	1.3%	1,260	1.3%	-
2029	-		1,133	0.5%	1,240	0.7%	1,270	0.8%	-
2030	-		1,140	0.6%	1,251	0.9%	1,282	0.9%	-
2031	-		1,147	0.6%	1,261	0.8%	1,293	0.9%	-
2032	-		1,154	0.6%	1,272	0.9%	1,306	1.0%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Compound Avg. 15 yr ('02 to '17)	#VALUE!	#VALUE!	#VALUE!
Compound Avg. 10 yr ('07 to '17)	-1.0%	-0.7%	-0.6%
Compound Avg. 5 yr ('12 to '17)	-1.4%	-0.9%	-0.8%
Compound Avg. 5 yr ('17 to '22)	-1.3%	-1.2%	-1.1%
Compound Avg. 10 yr ('17 to '27)	-0.7%	-0.5%	-0.4%
Compound Avg. 15 yr ('17 to '32)	-0.3%	0.0%	0.0%

HDD_wtd

NORMAL	43.3
EXTREME 90/10	54.0
EXTREME 95/5	57.0

Appendix B: POWER SUPPLY AREAS (PSAs)

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) after EE, PV and EV impacts

			2018 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2019	2020	2021	2022	2023	'19 to '23	'24 to '28	'29 to '33
RI	Blackstone Valley	RI	96.1%	105.4%	108.0%	(0.8)	(0.8)	(0.7)	(0.5)	(0.5)	(0.6)	(0.2)	(0.5)
RI	Newport	RI	96.1%	105.4%	108.0%	(0.4)	(0.4)	(0.5)	(0.3)	(0.3)	(0.4)	(0.1)	(0.4)
RI	Providence	RI	96.1%	105.4%	108.0%	(0.7)	(0.7)	(0.7)	(0.5)	(0.5)	(0.6)	(0.3)	(0.5)
RI	Western Narraganset	RI	96.1%	105.4%	108.0%	0.3	0.2	0.1	0.2	0.2	0.2	0.2	(0.2)

Year One Weather-Adjustment & Multi-Year Annual Growth (Summer) after EE & EV impacts, but before PV reductions

			2018 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2019	2020	2021	2022	2023	'19 to '23	'24 to '28	'29 to '33
RI	Blackstone Valley	RI	96.1%	105.4%	108.0%	(0.5)	(0.5)	(0.5)	(0.3)	(0.2)	(0.4)	(0.0)	(0.2)
RI	Newport	RI	96.1%	105.4%	108.0%	(0.1)	(0.2)	(0.2)	(0.0)	(0.0)	(0.1)	0.1	(0.2)
RI	Providence	RI	96.1%	105.4%	108.0%	(0.5)	(0.5)	(0.5)	(0.3)	(0.2)	(0.4)	(0.0)	(0.3)
RI	Western Narraganset	RI	96.1%	105.4%	108.0%	0.5	0.5	0.3	0.5	0.5	0.5	0.5	0.0

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (WINTER) after EE and EV impacts

			2017/18 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 10/90	for 05/95	2018	2019	2020	2021	2022	'18 to '22	'23 to '27	'28 to '32
RI	Blackstone Valley	RI	94.2%	100.1%	101.8%	(2.3)	(1.5)	(2.0)	(1.6)	(0.3)	(3.6)	(0.2)	0.8
RI	Newport	RI	94.2%	100.1%	101.8%	(1.9)	(1.1)	(1.7)	(1.4)	(0.0)	(1.8)	(0.0)	0.9
RI	Providence	RI	94.2%	100.1%	101.8%	(2.3)	(1.5)	(2.0)	(1.6)	(0.3)	(2.0)	(0.2)	0.8
RI	Western Narraganset	RI	94.2%	100.1%	101.8%	(1.3)	(0.5)	(1.1)	(0.8)	0.5	(1.2)	0.4	1.2

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current winter peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents can be applied to the current winter peaks to determine what the growth for each area is.

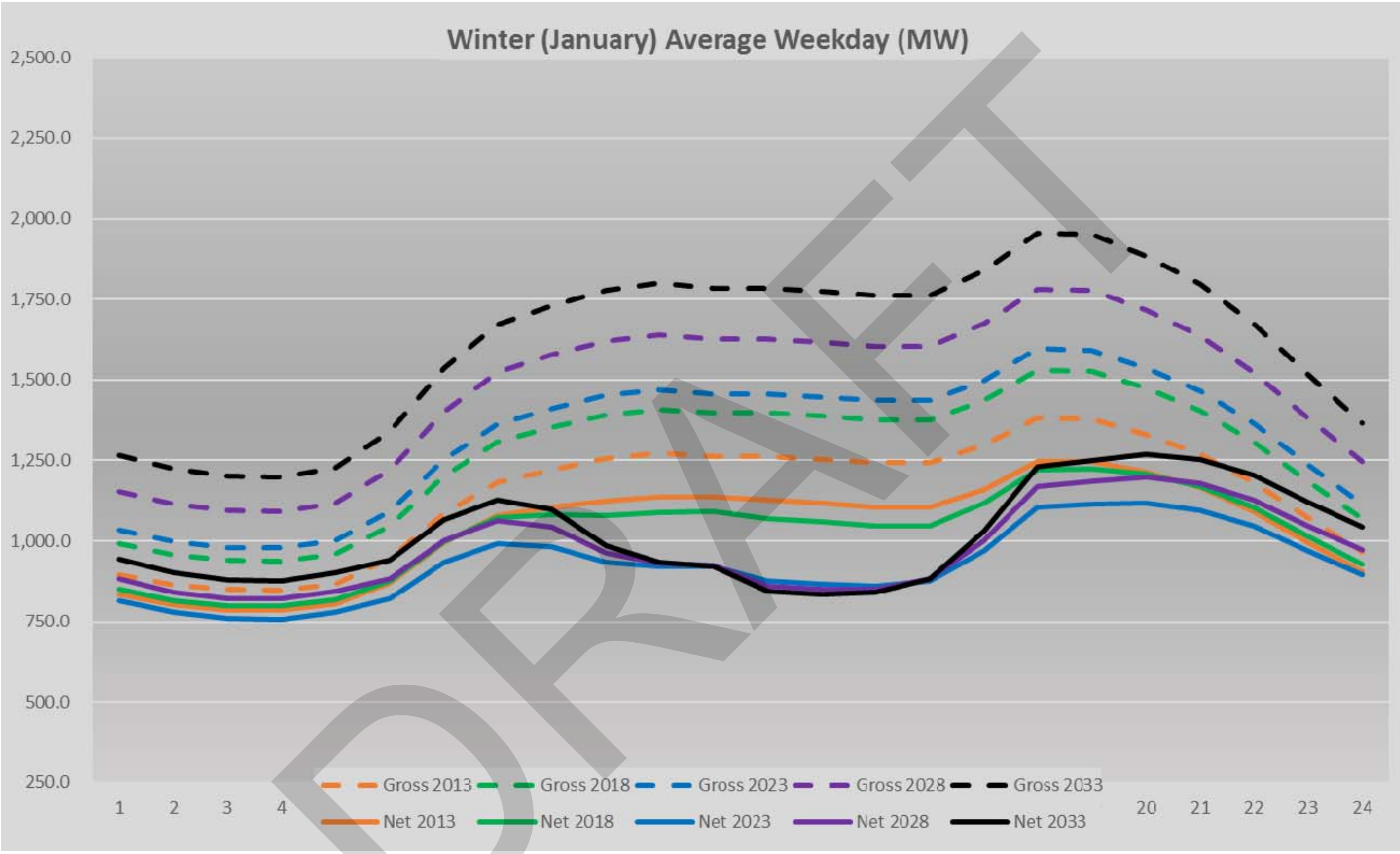
Appendix C: Historical Summer Peak Days and Hours

year	ri	dt_ri	hr_ri
2003	1,670.3	8/22/2003	15
2004	1,628.0	8/30/2004	15
2005	1,804.5	8/5/2005	15
2006	1,985.2	8/2/2006	15
2007	1,777.3	8/3/2007	15
2008	1,823.6	6/10/2008	15
2009	1,713.2	8/18/2009	15
2010	1,872.0	7/6/2010	15
2011	1,974.1	7/22/2011	16
2012	1,892.2	7/18/2012	15
2013	1,965.4	7/19/2013	15
2014	1,652.9	9/2/2014	16
2015	1,737.6	7/20/2015	15
2016	1,802.9	8/12/2016	16
2017	1,688.2	7/20/2017	16
2018	1,845.4	8/29/2018	17

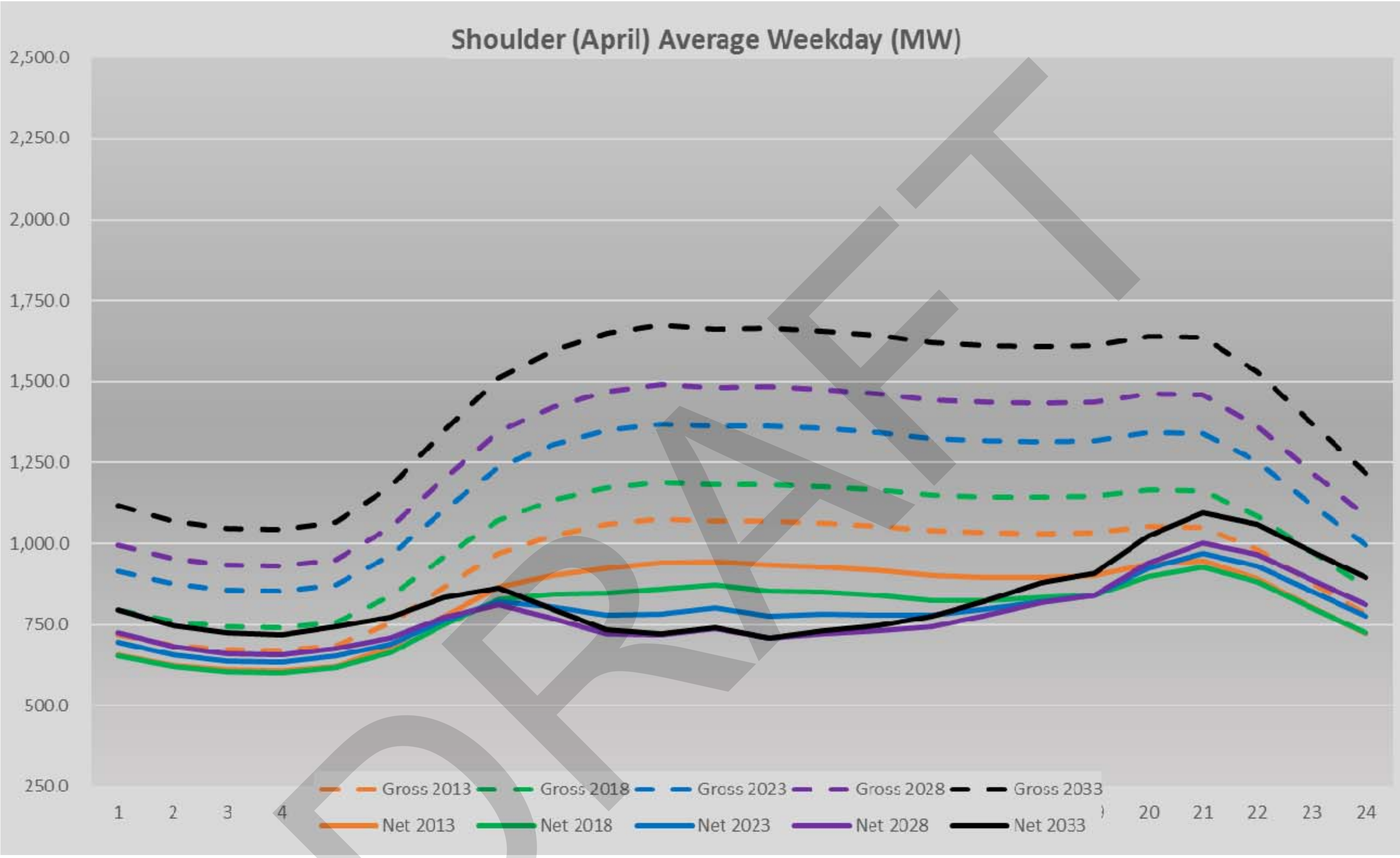
Appendix D

Load Shapes for Typical Day Types *

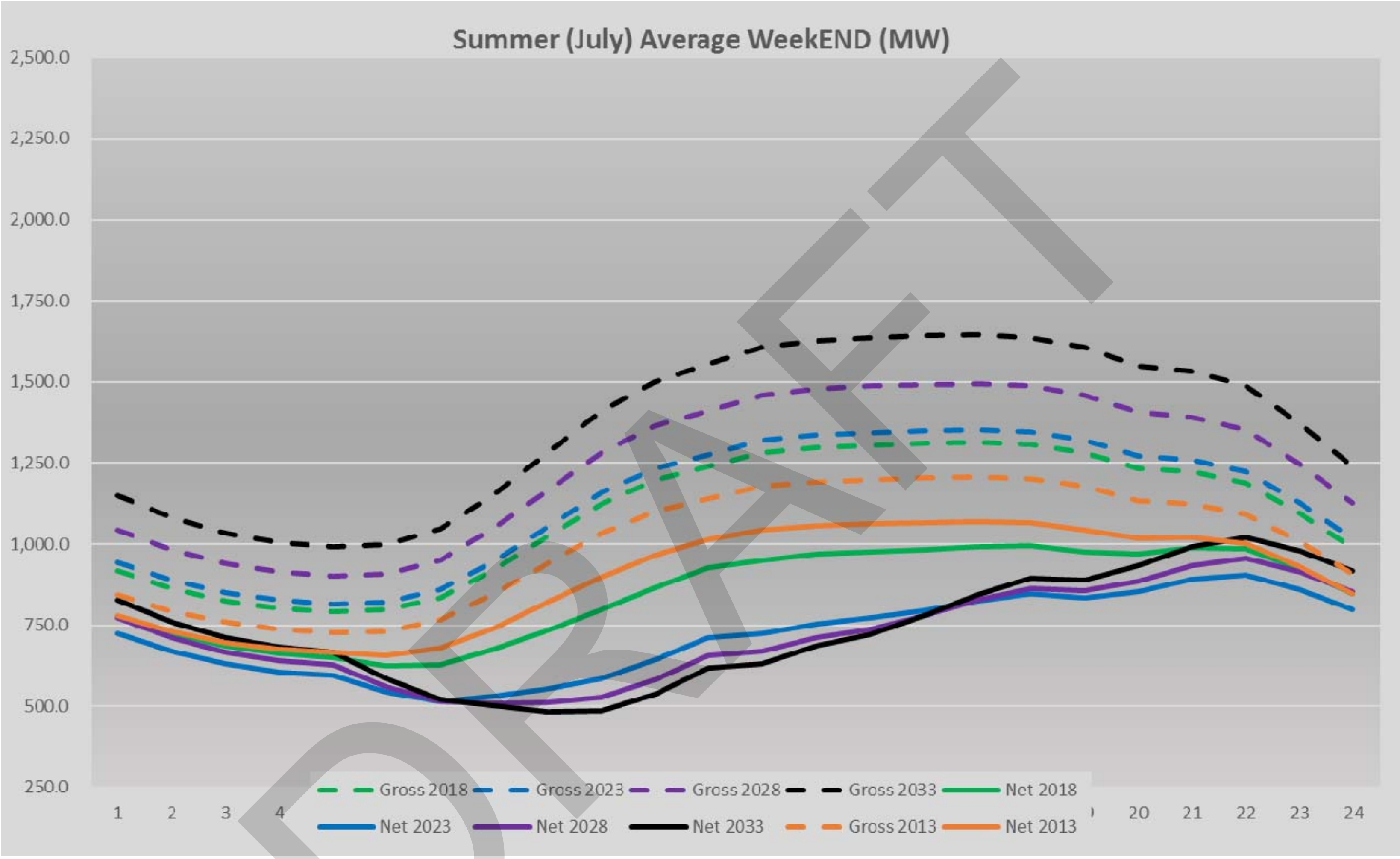
- Load shapes for peak and average summer days contained in body of report.

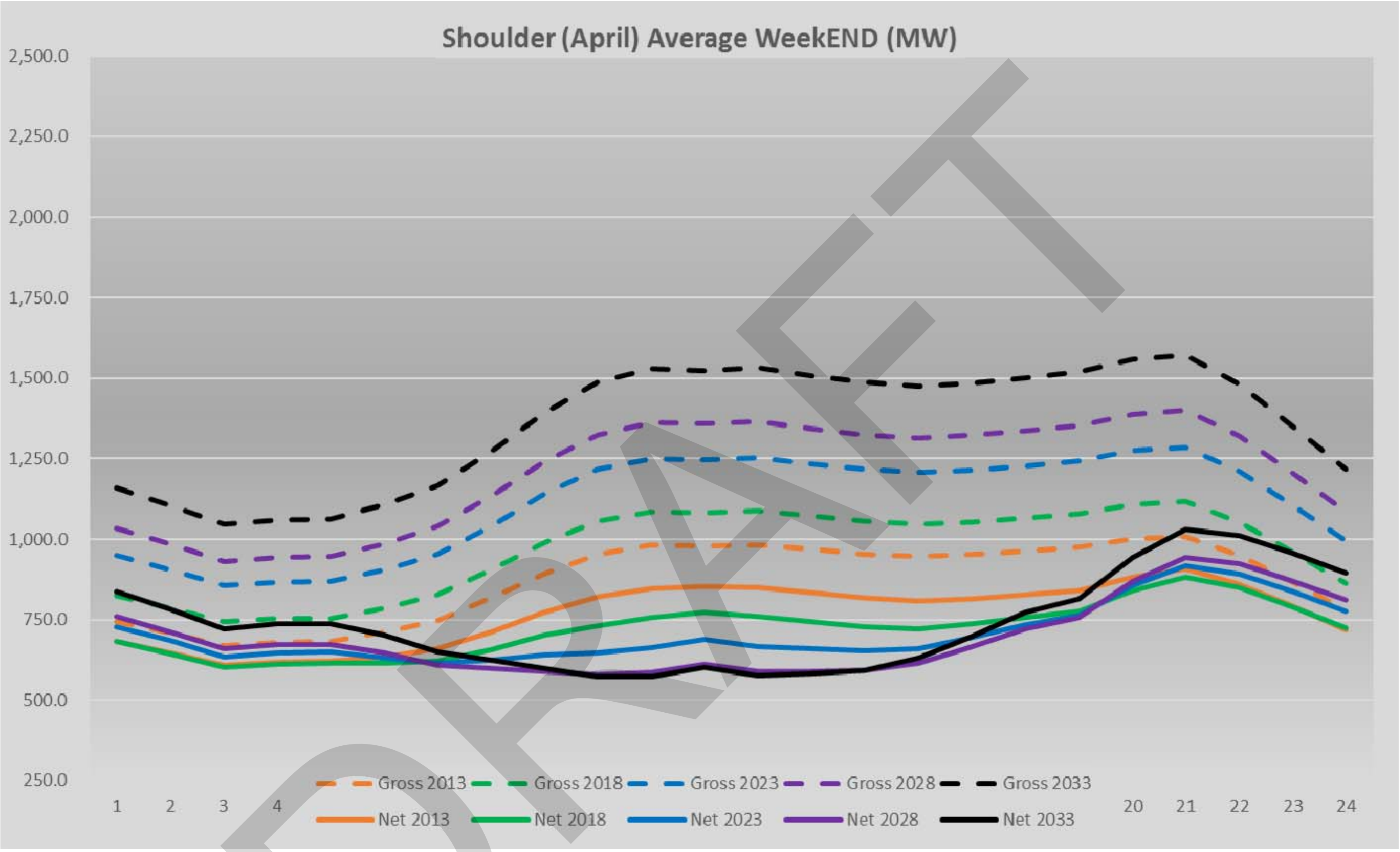


Winter (January) Average Weekday (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1
2
3
4
20
21
22
23
24
Gross 2013
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2013
Net 2018
Net 2023
Net 2028
Net 2033


Shoulder (April) Average Weekday (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1
2
3
4
20
21
22
23
24
Gross 2013
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2013
Net 2018
Net 2023
Net 2028
Net 2033

DRAFT


Summer (July) Average WeekEND (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1
2
3
4
20
21
22
23
24
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2018
Net 2023
Net 2028
Net 2033
Gross 2013
Net 2013



Shoulder (April) Average WeekEND (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1
2
3
4
20
21
22
23
24
Gross 2013
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2013
Net 2018
Net 2023
Net 2028
Net 2033

Appendix 3 – Distribution Planning Guide

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ______________________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document		

Distribution Planning Criteria Strategy
Table of Contents

Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0 1	10/14/2009 2/15/2011	Initial draft Final approved document	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:

- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

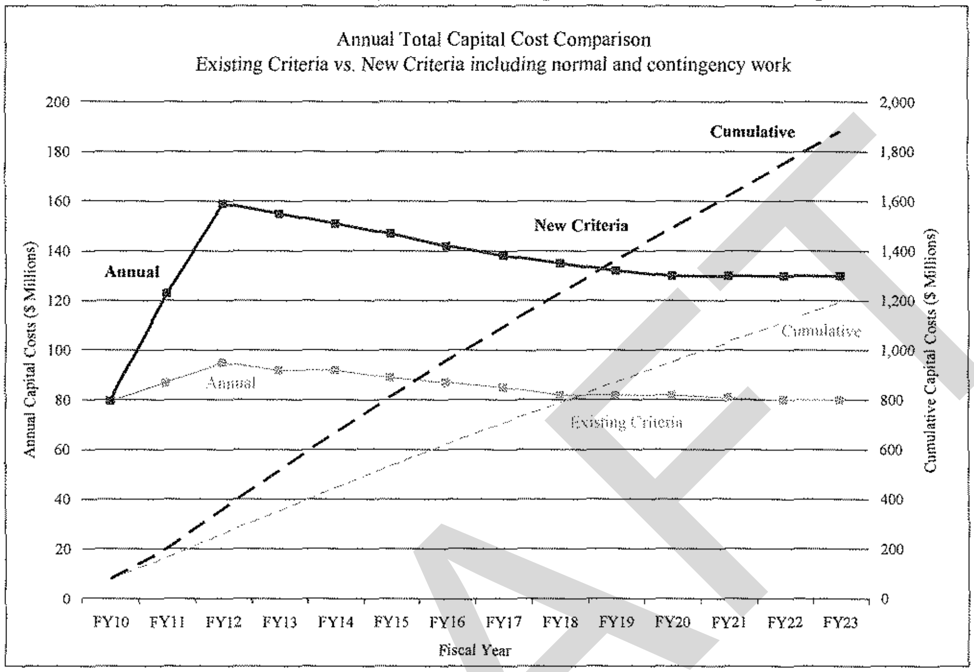
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

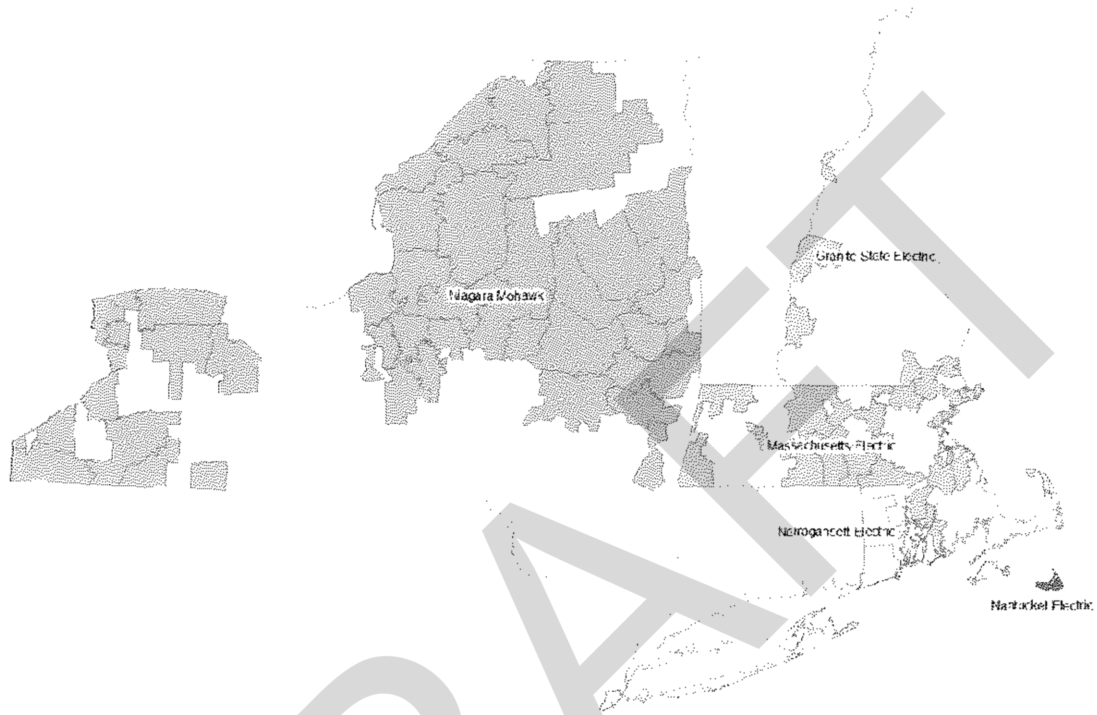
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

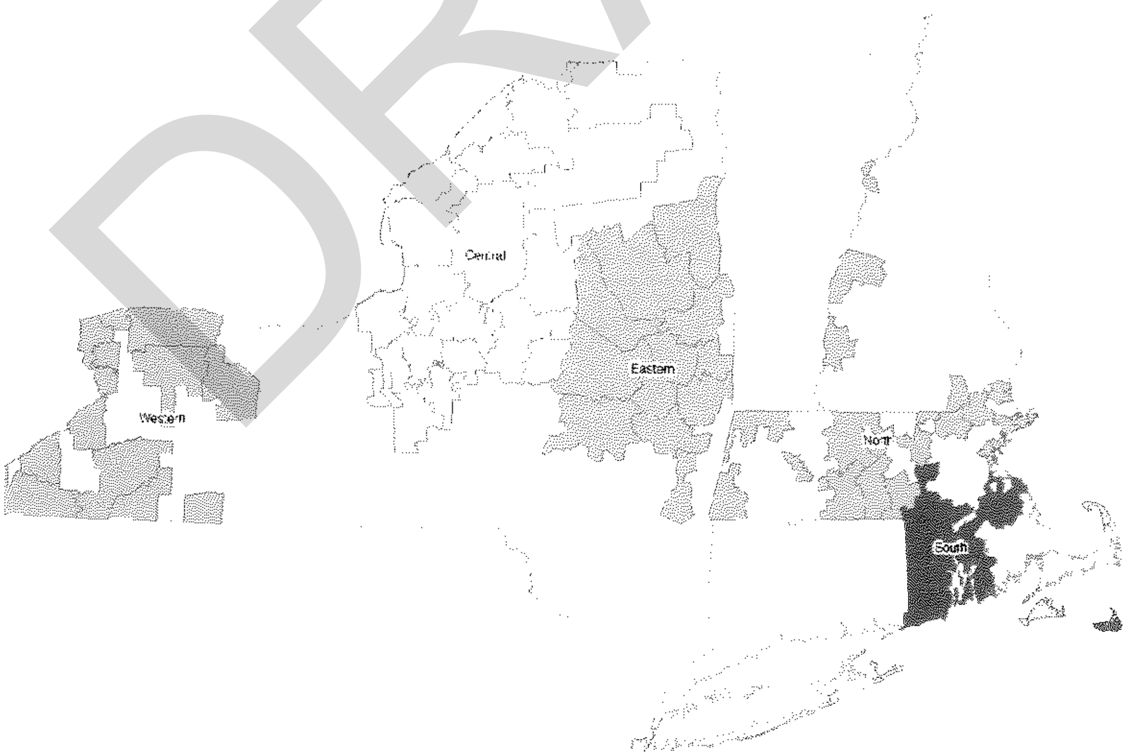
Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

Companies

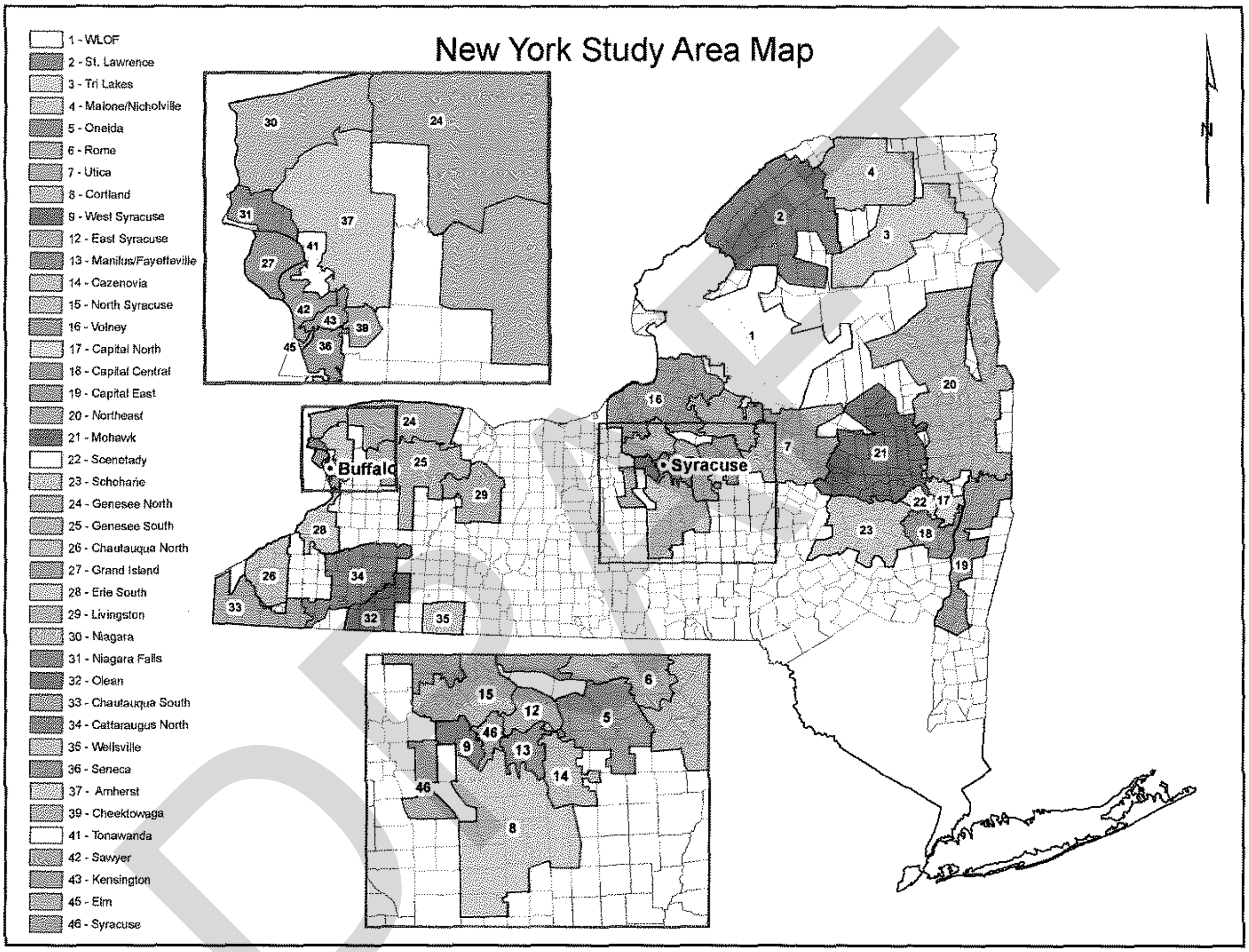


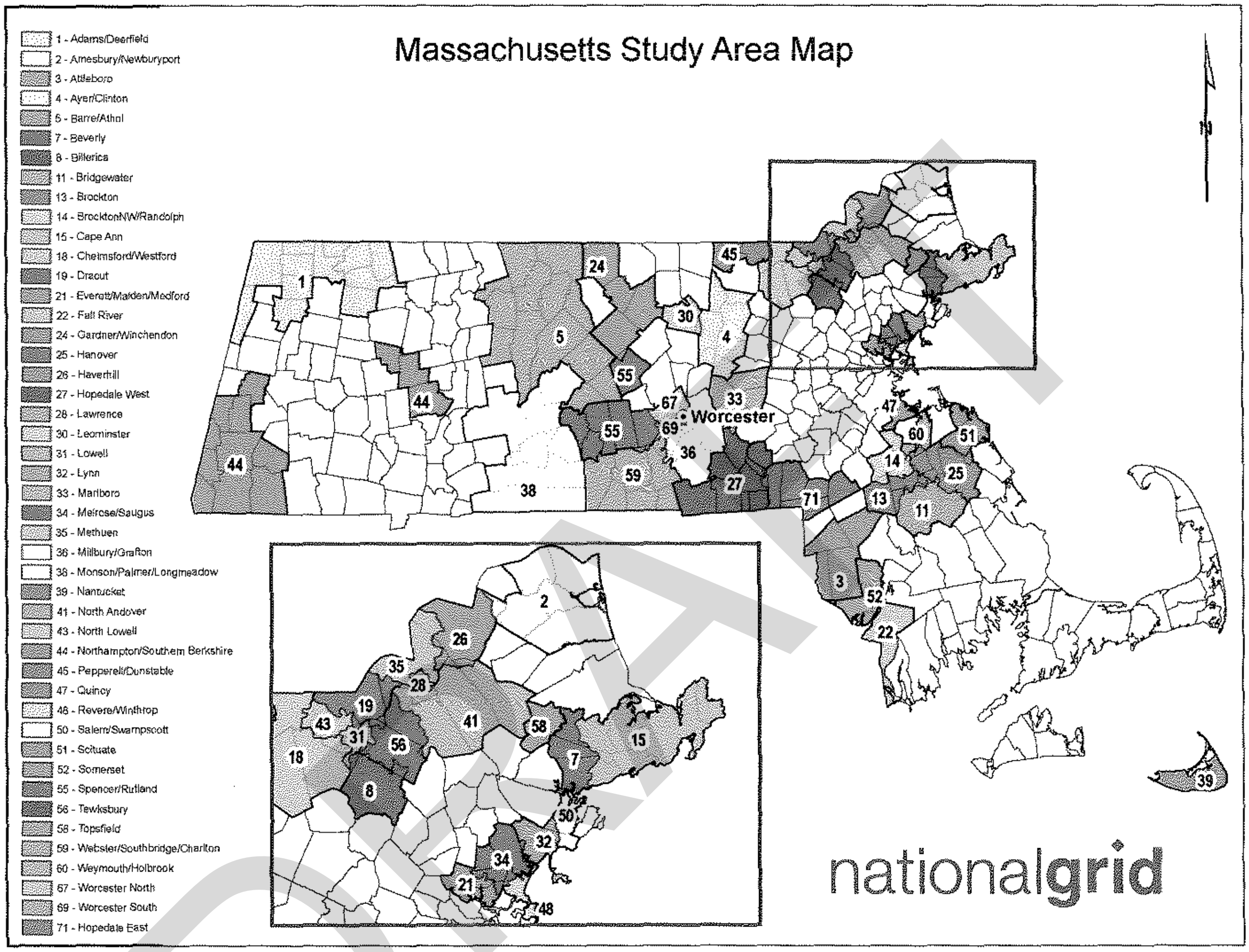
Divisions

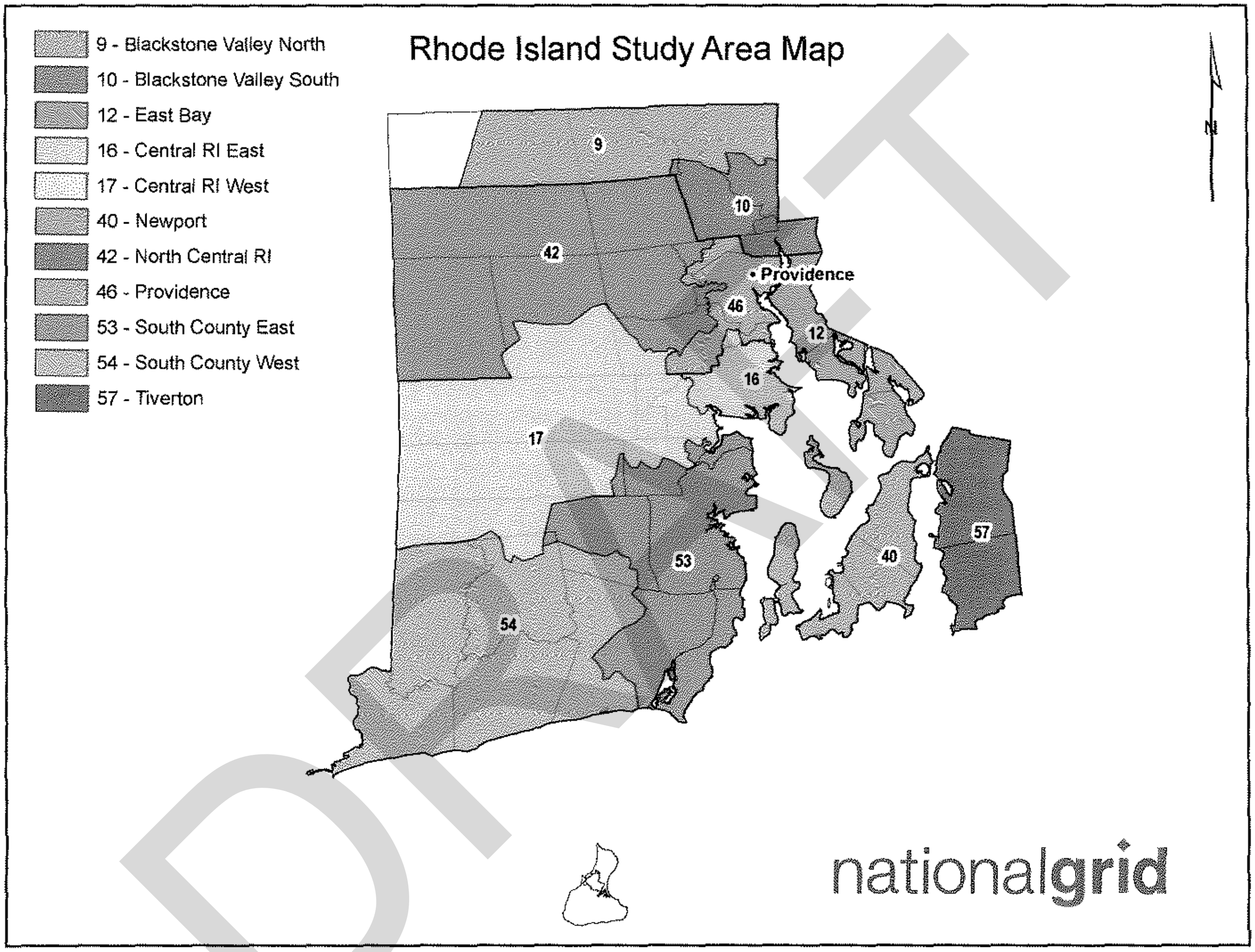


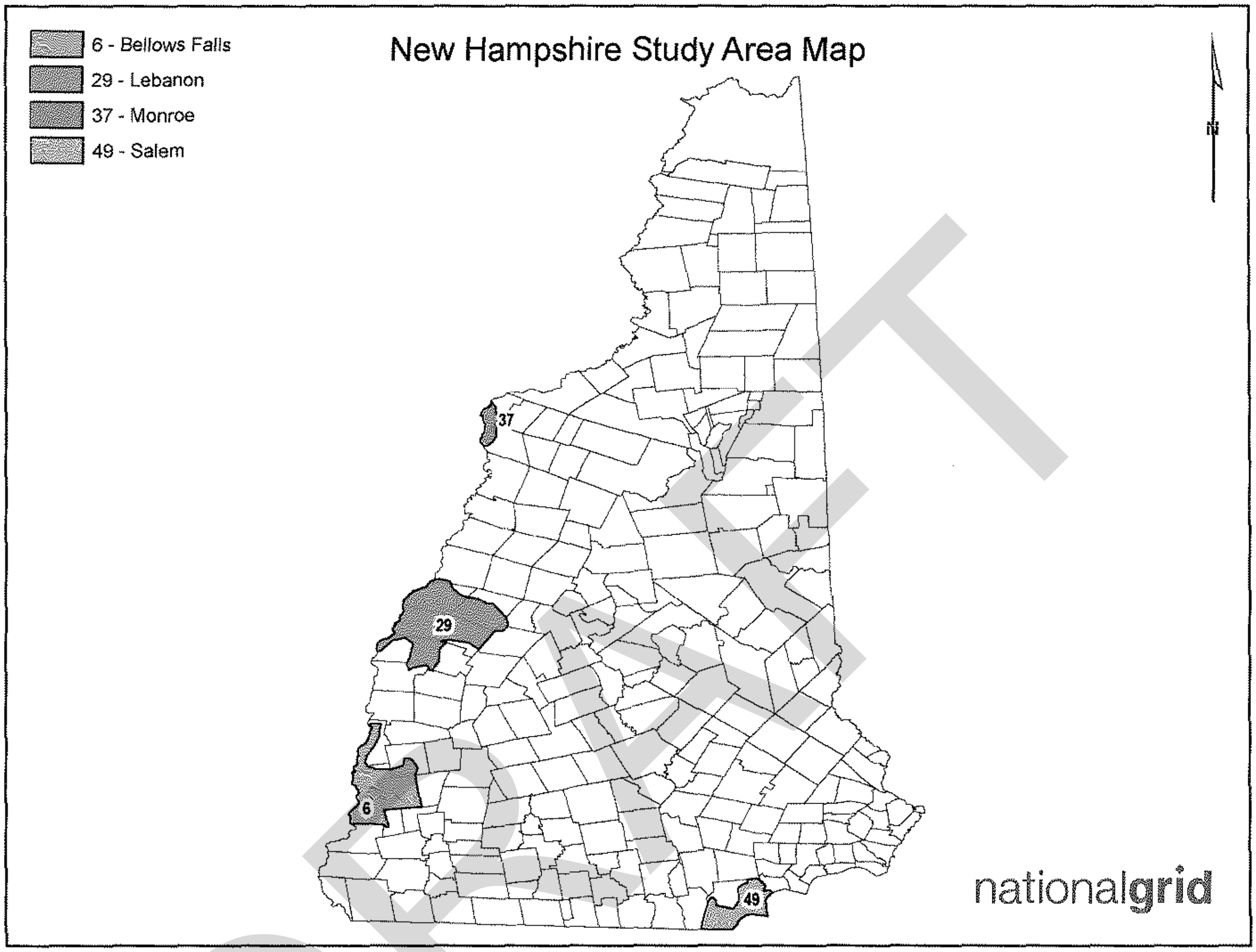
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
1 - Adams/Deerfield
2 - Amesbury/Newburyport
3 - Attleboro
4 - Ayer/Clinton
5 - Barre/Athol
7 - Beverly
8 - Billerica
11 - Bridgewater
13 - Brockton
14 - BrocktonNW/Randolph
15 - Cape Ann
18 - Chelmsford/Westford
19 - Dracut
21 - Everett/Malden/Medford
22 - Fall River
24 - Gardner/Winchendon
25 - Hanover
26 - Haverhill
27 - Hopedale West
28 - Lawrence
30 - Leominster
31 - Lowell
32 - Lynn
33 - Marlboro
34 - Melrose/Saugus
35 - Methuen
36 - Millbury/Grafton
38 - Monson/Palmer/Longmeadow
39 - Nantucket
41 - North Andover
43 - North Lowell
44 - Northampton/Southern Berkshire
45 - Pepperell/Dunstable
47 - Quincy
48 - Revere/Winthrop
50 - Salem/Swampscott
51 - Scituate
52 - Somerset
55 - Spencer/Rutland
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
69 - Worcester South
71 - Hopedale East
Worcester
nationalgrid


Rhode Island Study Area Map
9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
9
10
42
Providence
46
12
16
17
57
40
53
54
N
nationalgrid


New Hampshire Study Area Map
6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
37
29
6
49
N
nationalgrid

Appendix 4 – Projects Screened for NWA

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Date Initiated
1	C080657	RI VVO IS/IT Software	Not suitable for comparison to NWA alternative solution, as this project was opened for software needed for the RI VVO program.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	5/30/2018
2	C080895	RI VVO Exp - Woonsocket 26 Distribution	Upon further evaluation, the VVO projects are not proposed to address system concerns, the program is used to reduce customer cost and customer energy and therefore there are no comparable NWA projects at this time.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/2/2018
3	C080896	RI VVO Exp - Dexter 36 Distribution	Upon further evaluation, the VVO projects are not proposed to address system concerns, the program is used to reduce customer cost and customer energy and therefore there are no comparable NWA projects at this time.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/2/2018
4	C080899	RI VVO Exp - Woonsocket 26 Substation	Upon further evaluation, the VVO projects are not proposed to address system concerns, the program is used to reduce customer cost and customer energy and therefore there are no comparable NWA projects at this time.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/2/2018
5	C080900	RI VVO Exp - Dexter 36 Substation	Upon further evaluation, the VVO projects are not proposed to address system concerns, the program is used to reduce customer cost and customer energy and therefore there are no comparable NWA projects at this time.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/2/2018
6	C081006	Franklin Square Breaker Replacement	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	7/26/2018
7	C081007	Davisville 3V0 Distribution Substation	Does not meet NWA screening requirements - Programmatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/26/2018
8	C081008	Wolf Hill 3V0 Distribution Substation	Does not meet NWA screening requirements - Programmatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/26/2018
9	C081009	Pontiac 3V0 Distribution Substation	Does not meet NWA screening requirements - Programmatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	7/26/2018

10	C081341	Cable Replacement Woodland Manor-Coven	Does not meet NWA screening requirements - Asset Condition Driven Project, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	9/13/2018
11	C081572	51J12/154J8 Feeder Tie	Does not meet NWA screening requirements - Timeline of need was immediate, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	10/9/2018
12	C081675	New Lafayette substation 115/12kV	Does not meet NWA screening requirements - Project opened only to transfer PS&I charges	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	10/19/2018
13	C081716	RI Replacement Project ACNW Vault Vent Blowers	Does not meet NWA screening requirements - Specific project opened as part of the program to provide manhole ventilation methods to promote natural exchange of air in the duct systems	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	10/23/2018
14	C082439	Franklin Sq-Replace 11kV Substation Equipment	Does not meet NWA screening requirements - Asset Condition Driven Project, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	Asset Condition	1/23/2019
15	C082757	Replacement of OH Conductor Ledge Rd	Does not meet NWA screening requirements - Asset Condition Driven Project, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	Asset Condition	2/23/2019

Appendix 5 – 2019 SRP Marketing and Engagement Plan

SYSTEM RELIABILITY PROCUREMENT

2019 Marketing and Engagement Plan

Table of Contents

1. Introduction

The 2019 System Reliability Procurement (SRP) Marketing and Engagement Plan will provide information to the public, with the target audience being third-party solution providers, regarding the status, usefulness, and use-case scenarios of the Rhode Island System Data Portal (Portal).

The Rhode Island System Data Portal is an online, interactive mapping system created for developers to gain visibility to the electric grid distribution system. The Portal contains distribution feeder and substation information including feeder characteristics such as geographic locations, voltage, feeder ID, planning area, substation source as well as loading and available distribution generation hosting capacity. The Portal went live on June 30, 2018 and is a new digital asset of National Grid for use by third-party solution providers.

There may be additional opportunities for installations of alternative solutions and technologies that reduce peak load outside of National Grid's[1] consideration and proposal of cost-effective Non-Wires Alternative (NWA) projects. A Marketing and Engagement Plan will nurture these inherent opportunities with the work the Company is doing on the Portal, and to encourage and engage Distributed Energy Resource (DER) solution providers to support the strategic deployment of these solutions to benefit constrained areas.

Such engagement will enable third-party solution providers and vendors to more easily access available information about National Grid's electric distribution system in Rhode Island and therefore further enable these solution providers to create, submit and develop innovative energy solutions for Rhode Island customers. The Marketing and Engagement Plan upholds the commitment of National Grid and the State of Rhode Island to advance a more reliable, safe, and cost-effective energy landscape for residents and businesses of Rhode Island.

The Company proposes the 2019 SRP Marketing and Engagement Plan to promote the Portal and associated resources described in the 2018 and 2019 System Reliability Procurement Reports as they exist and are developed.

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

2. Purpose

The purpose of the Marketing and Engagement Plan is to raise awareness of and drive engagement with the Rhode Island System Data Portal and associated map resources to all appropriate Rhode Island parties, with the primary target audience being third-party solution providers.

3. Timeline

The 2019 SRP Marketing and Engagement Plan will take place during calendar year 2019, effectively starting on January 1 and ending on December 31.

4. Program Budget

The budget for SRP Marketing and Engagement is $84,000 to support this initiative in 2019. The Company estimates that $56,000 will be needed to support the development and distribution of marketing materials and vendor costs. The Company estimates that $28,000 will be needed to support program planning and administration, which includes managing program vendors, the program tracking mechanisms and evaluation processes.

Please note that this budget does not include funding associated with marketing for other programs such as RE Growth, Connected Solutions, and EE. The budget for the 2019 Marketing and Engagement Plan only accounts for marketing and engagement efforts with respect to the Rhode Island System Data Portal.

5. Outreach Channels

This section provides an overview of the primary business-to-business (B2B) outreach and engagement channels National Grid plans to implement through the Marketing and Engagement Plan for calendar year 2019 to engage with third-party solution providers.

5.1 Webinars

National Grid plans on presenting in-depth technical web-based walkthroughs in webinars. Webinar events and hosting will be coordinated by a third-party marketing vendor, with National Grid employees providing the walkthrough, question response, and content.

Webinars connect National Grid with third-party solution providers, provide these vendors with pertinent information and guidance on how to use the Portal, and provide an open forum for questions and answers.

National Grid plans to provide four webinars throughout the calendar year, with one performed each quarter. Additional webinars may be held as needed depending on any major updates made to the Portal in calendar year 2019.

5.2 In-Person Demonstrations

National Grid plans on presenting in-depth technical in-person demonstrations. In-person demonstrations will be coordinated and hosted by National Grid.

In-person demonstrations are similar to webinars in purpose, with the added benefit that hands-on guidance can be provided to the vendor during the demonstration.

National Grid plans to provide two in-person demonstrations, with one performed per half year for calendar year 2019. Additional in-person demonstrations may be held as needed depending on external stakeholder or vendor meeting and event opportunities.

5.3 Email

National Grid plans on performing email outreach to third-party solution providers. Email campaigns will be coordinated and delivered by a third-party marketing vendor.

Email marketing helps to maintain and raise awareness for current and new vendors, notify vendors of any major changes or updates to the Portal, and impresses upon vendors that the Portal is a useful tool to use as part of project and proposal development.

National Grid plans on performing four email campaigns, with one campaign performed per quarter, to maintain awareness of the Portal among the current vendor base. Additional email marketing to National Grid's vendors will occur as needed for major updates. Email marketing for any new vendors will occur as needed to welcome and onboard the new vendors.

5.4 Digital Advertisements

National Grid plans on continuing digital advertisements through calendar year 2019. National Grid will work with a third-party marketing vendor to place digital advertisements.

Digital advertisement placements generate awareness for third-party solution providers overall. Digital advertisements have the added benefit of generating awareness for vendors who are not yet in National Grid's vendor list and therefore aren't receiving emails or webinar/demo notifications.

5.5 Paid Search Terms

National Grid plans to continue the paid web search terms strategy through calendar year 2019. National Grid will work with a third-party marketing vendor to effectuate paid search terms to market the Portal by Search Engine Optimization (SEO) with search engine keywords by paying to prioritize the Portal in identified searches via engines like Google, Yahoo, Microsoft Bing, etc.

Search Engine Optimization is the process of maximizing the number of visitors to a website by ensuring that the site appears high on the list of results returned by the search engine.

Paid search terms enable the Portal to be populated much higher in a web search results list. This search result improvement allows vendors to more easily receive search results relevant to the Portal. A web search is another venue where new vendors can find out about the Portal through the use of related terminology.

5.6 Social Media Engagement

National Grid plans to post updates on the Company pages of LinkedIn to enable another venue of outreach to new and existing vendors. National Grid will create and manage these posts directly.

Posting important updates on a business-oriented social media platform will help to maintain awareness of the Portal and to concisely call out important changes to the Portal for vendors.

5.7 Earned Media

National Grid plans to explore developing strategic articles to place in appropriate industry and trade publications. Publishing industry articles will help highlight the Portal and its purpose to vendors in an additional channel to email and web outreach.

5.8 Vendor Contact List

National Grid plans to procure a contact list of vendors to expand the Company's scope of outreach to new vendors. Vendor contact lists are available from third-party outreach vendors.

Procuring a vendor contact list will enable National Grid to directly contact vendors, especially new vendors, who are not currently being reached via email marketing or web advertisements.

5.9 Contact Channels

National Grid plans to create a dedicated email distribution list for all appropriate inquiries related to the Portal. National Grid also plans to coordinate existing email distribution lists on the Portal so vendors can optimally communicate with the topically-corresponding internal team.

6. Outreach Performance Evaluation

National Grid will continuously monitor, track, and assess the effectiveness of the 2019 SRP Marketing and Engagement Plan.

In order to achieve the purpose of the Marketing and Engagement Plan, the outreach efforts are to meet or exceed the goals outlined in this section.

National Grid will use the following performance metrics and goals for Marketing and Engagement Plan evaluation:

6.1 Webinars

Attendance: Achieve average webinar attendance greater than or equal to 35. There is no industry average benchmark because webinar attendance varies per event and topical substance.

6.2 Email

Open Rate: Achieve an average email open rate greater than or equal to 15% for email campaigns. The industry average email open rate benchmark is 15%.

6.3 Digital Advertisements

1. Ad Impressions: Achieve average ad impressions greater than or equal to 400,000 for digital advertisements. There is no industry average benchmark for ad impressions because impressions vary based on budget.
2. Click-Through Rate (CTR): Achieve an average CTR greater than or equal to 0.60% for digital advertisements. The industry average CTR benchmark is 0.40%.

6.4 Paid Search Terms

Web Rankings: Maintain the Rhode Island System Data Portal in the top five web search results for our top-performing paid search terms. (The Portal will be returned as one of the top five search results when a top-performing paid search term is used.) The industry standard for Search Engine Optimization (SEO) is for rankings to appear "above the fold", or on page one of the search results.

6.5 Web Traffic

Total Site Visit: Achieve average total site visits greater than or equal to 1,500. There is no industry standard for web traffic specific to one designated landing page.

Table 1. Outreach Performance Evaluation Goals

Outreach Channel	Corresponding Metric	Goals
Webinars	Attendance	Average Attendance ≥ 35
Email Outreach	Open Rate	Average Open Rate ≥ 15%
Digital Advertisements	Click-Through Rate (CTR)	Average CTR ≥ 0.60%
Digital Advertisements	Ad Impressions	Average Ad Impressions ≥ 400k
Paid Search Terms	Web Rankings	Web Rankings ≥ 5th
Web Traffic	Total Site Visits	Average Total Site Visits ≥ 1,500

Appendix A: Table of Terms

Below is a table to help provide clarity on the marketing and related terms.

Term	Definition
Clicks	The number of times an individual selects or clicks on an advertisement or its equivalent.
Click-Through Rate (CTR)	The rate of clicks per impression, calculated by clicks divided by impressions. This represents, in part, the percentage of times users have clicked on a banner.
Digital Ad Placements	A specific group of advertisements on which an advertiser can choose to place their ads using placement targeting. A digital placement is one that takes place on digital media, such as the internet.
Impressions	The number of times an advertisement was viewed.
Non-Wires Alternative (NWA)	The inclusive term for any electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment".
Open Rate	The percentage of people who opened an email out of the total number of recipients. This number will include people who opened the email more than once. An indicator of subject line success and topic relevance.
Paid Search Term	A phrase or word on which advertisers bid to trigger their website or webpage to be shown to relevant users, dependent on term used.
Rankings	The position of a website or webpage in a search result list, dependent on the term used in the search engine.
Returning Site Visit	The number of times a unique first-time visitor returns to the website.
Search Engine Optimization (SEO)	The process of maximizing the number of visitors to a website by ensuring that the site appears high on the list of results returned by the search engine.
Total Site Visits	The total number of visits of individuals to a website during a given period. Total site visits are the sum of unique site visits and returning site visits.
Unique Site Visit	The number of visits of distinct individuals to a website during a given period. Does not include the number of revisits that an individual makes to the website.
Webinar	A live, web-based video conference that uses the internet to connect the individual hosting the conference to an audience of viewers. A portmanteau of the terms "web seminar".

Appendix 6 – 2019 SRP Marketing and Engagement Plan Year-to-Date Results

SYSTEM RELIABILITY PROCUREMENT

2019 Marketing and Engagement Plan

Year-to-Date Results

September 30, 2018 – August 31, 2019

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1. Executive Summary

The purpose of the SRP Marketing and Engagement Plan Year-to-Date Results is to illustrate to regulators and stakeholders the level of effectiveness achieved with the current SRP Marketing and Engagement Plan efforts and, therefore, to assess the potential level of engagement for third-party solution providers with the Rhode Island System Data Portal (Portal).

This report summarizes the outreach and engagement efforts and results for the Portal as of August 31, 2019. The outreach and engagement performed going into and through the 2019 calendar year supported education and built awareness of the Portal for third-party solution providers and stakeholders.

The Portal advertising campaign maintained strong performance throughout the year. With a monthly average of 565,011 impressions and 3,856 clicks on the advertisements for the Portal, marketing efforts have continually exceeded the Company's original target goals of 400,000 impressions and 1,500 clicks over the past year and a click rate above the industry benchmark of 0.60%.

- Average Impressions: 565,011
- Average Clicks: 3,856
- Average Click Rate: 0.68%

The Company has also tracked Google's ranking of the Portal webpage and all four targeted paid search terms are now ranked second in the Google search results list.

The Company has determined that webinar outreach may be reaching saturation, as attendance did not meet targets this year to date. This factored into the Company's decision to pare down the webinar events to two from four going into the 2020 SRP Outreach and Engagement Plan.

To date, the Marketing & Engagement Plan remains on track to achieving the campaign objective:

> *To raise awareness and drive engagement with the Rhode Island System Data Portal and associated map resources to all appropriate Rhode Island parties, with the primary target audience being third-party solution providers, interested in and capable of developing and submitting innovative energy solutions to uphold National Grid and the State of Rhode Island's commitment to advancing a more reliable, safe and cost-efficient energy landscape for Ocean State residents and businesses.*

2. Campaign Performance Evaluation

National Grid will continuously monitor, track, and assess the effectiveness of the 2019 SRP Marketing and Engagement Plan.

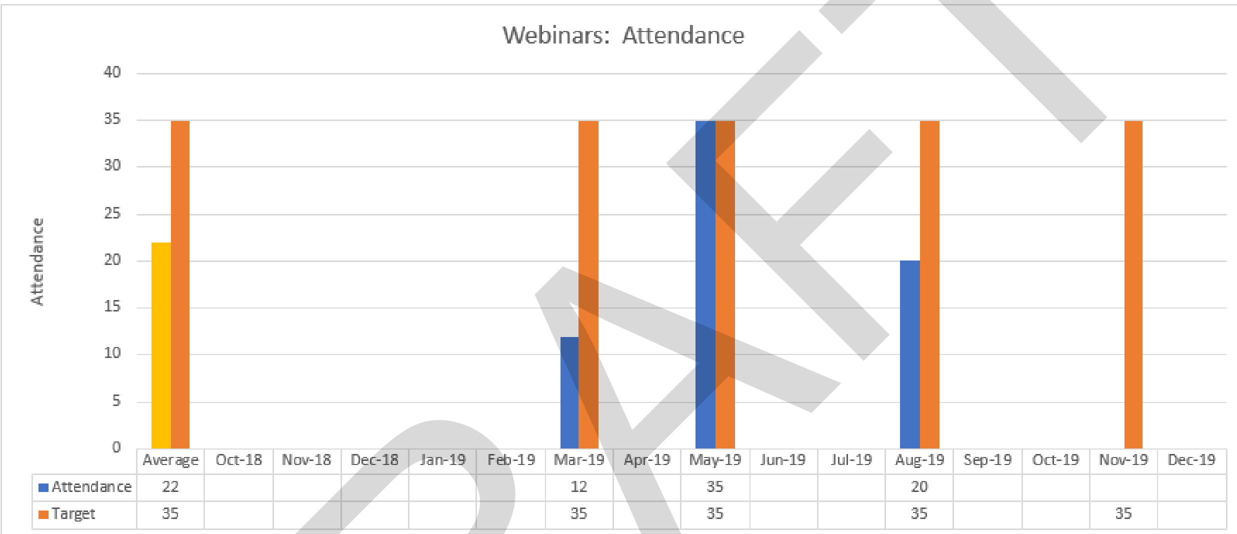
National Grid will evaluate using the metrics outlined in the 2019 Marketing and Engagement Plan and summarized in the table below.

Table 1. Campaign Performance Evaluation Goals

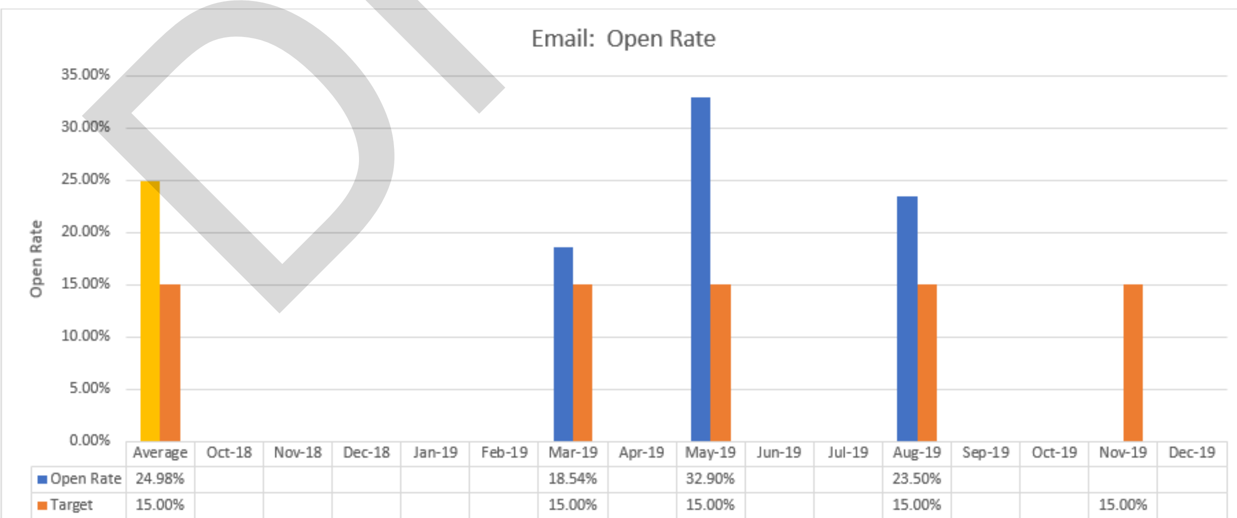
Outreach Channel	**Corresponding Metric**	**Goal**
Webinars	Attendance	Average Attendance ≥ 35
Email Outreach	Open Rate	Average Open Rate ≥ 15%
Digital Advertisements	Click-Through Rate (CTR)	Average CTR ≥ 0.60%
Digital Advertisements	Ad Impressions	Average Ad Impressions ≥ 400k
Paid Search Terms	Web Rankings	Web Rankings ≥ 5th
Web Traffic	Total Site Visits	Average Total Site Visits ≥ 1500

3. Campaign Performance Measurement

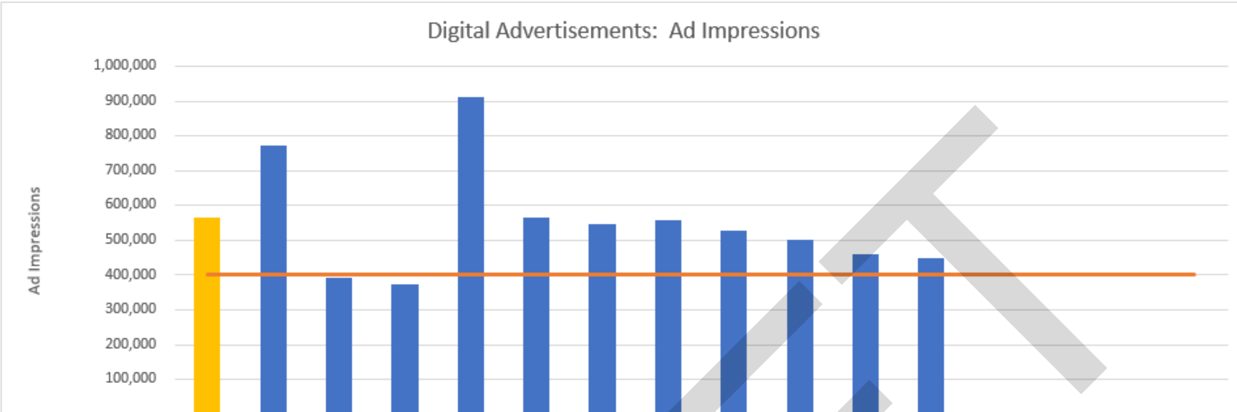
The charts in this section summarize the raw data in Appendix B and Appendix C for the relevant, targeted evaluation goals.



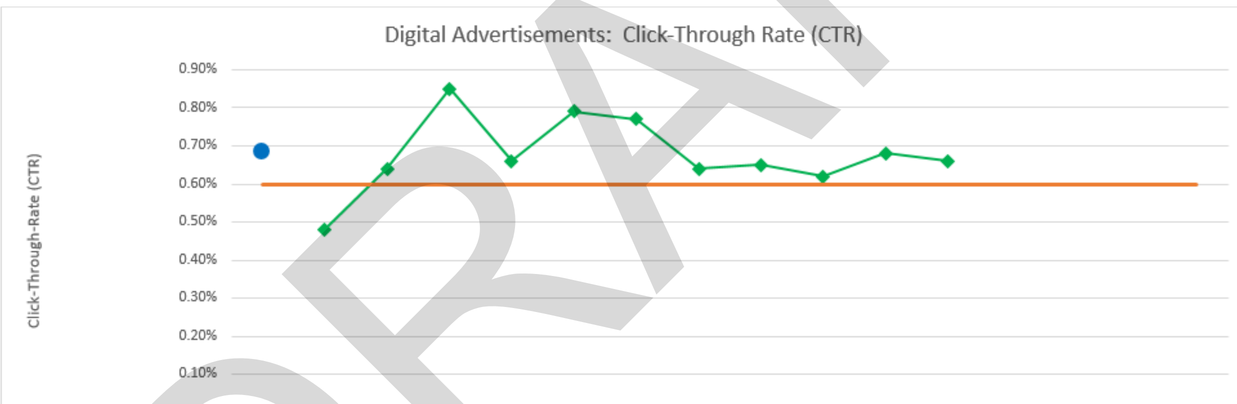
	Average	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Attendance	22						12		35			20				
Target	35						35		35			35			35	



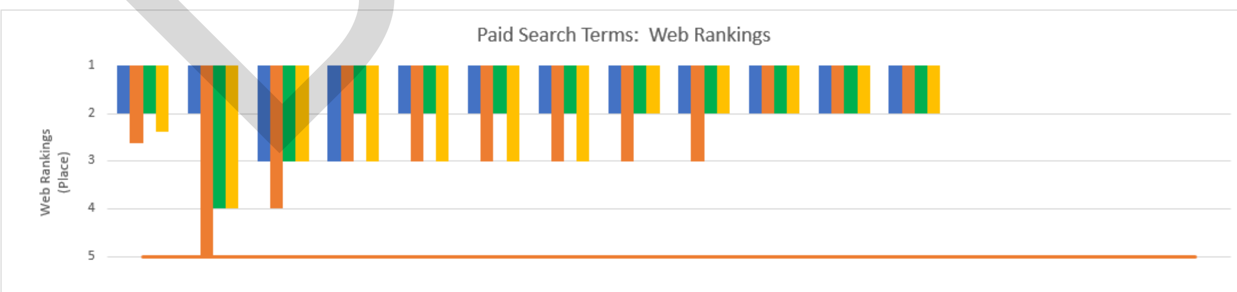
	Average	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Open Rate	24.98%						18.54%		32.90%			23.50%				
Target	15.00%						15.00%		15.00%			15.00%			15.00%	



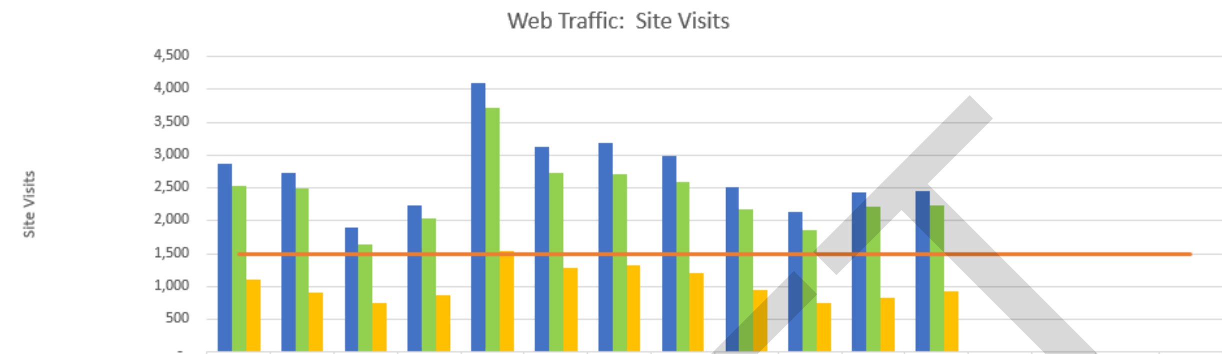
	Average	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Ad Impressions	565,011	772,393	391,044	374,490	910,668	564,163	545,910	557,943	528,923	503,088	458,937	450,455				
Target	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000



	Average	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Click-Through Rate (CTR)	0.68%	0.48%	0.64%	0.85%	0.66%	0.79%	0.77%	0.64%	0.65%	0.62%	0.68%	0.66%				
Target	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%	0.60%



	Average	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Series1	2	2	3	3	2	2	2	2	2	2	2	2				
Series2	2.63	5	4	3	3	3	3	3	3	2	2	2				
Series3	2	4	3	2	2	2	2	2	2	2	2	2				
Series4	2.375	4	3	3	3	3	3	2	2	2	2	2				
Series5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5



	Average	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Total Site Visits	2,869	2,731	1,891	2,228	4,096	3,133	3,192	2,995	2,514	2,132	2,438	2,453				
New Visitors	2,529	2,499	1,639	2,031	3,718	2,724	2,706	2,599	2,168	1,859	2,223	2,237				
Returning Visitors	1,099	909	752	863	1,534	1,281	1,325	1,199	944	752	839	921				
Target for Total Visits	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500

4. Continuous Improvement: Next Steps

The outreach and engagement results demonstrate that the team will need to continue to adjust the campaign settings within AdSense to utilize the budget and maximize clicks and impressions and to maintain rankings achieved in 2019. The team will continue to track the marketing metrics for alignment with plan goals. The team will incorporate lessons learned in 2019 into the 2020 plan including the reduction of webinars to two annually and the addition of a developer focus group.

Appendix A: Table of Terms

Below is a table to help provide clarity on the marketing and related terms used in this Monthly Report.

Term	Definition
Clicks	The number of times an individual selects or clicks on an advertisement or its equivalent.
Click-Through Rate (CTR)	The rate of clicks per impression, calculated by clicks divided by impressions. This represents, in part, the percentage of times users have clicked on a banner.
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Open Rate	The percentage of people who opened an email out of the total number of recipients. This number will include people who opened the email more than once. An indicator of subject line success and topic relevance.
Paid Search Term	A phrase or word on which advertisers bid to trigger their website or webpage to be shown to relevant users, dependent on term used.
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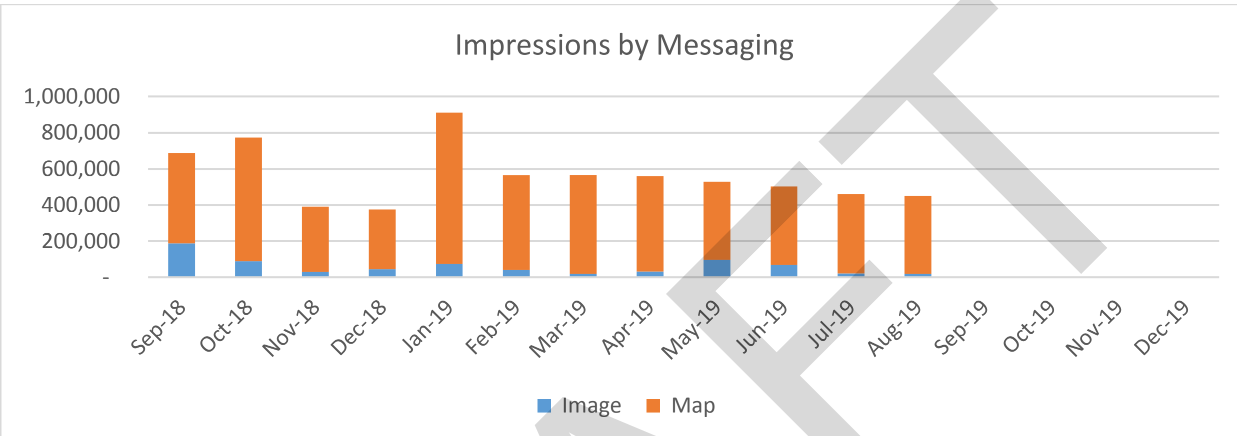
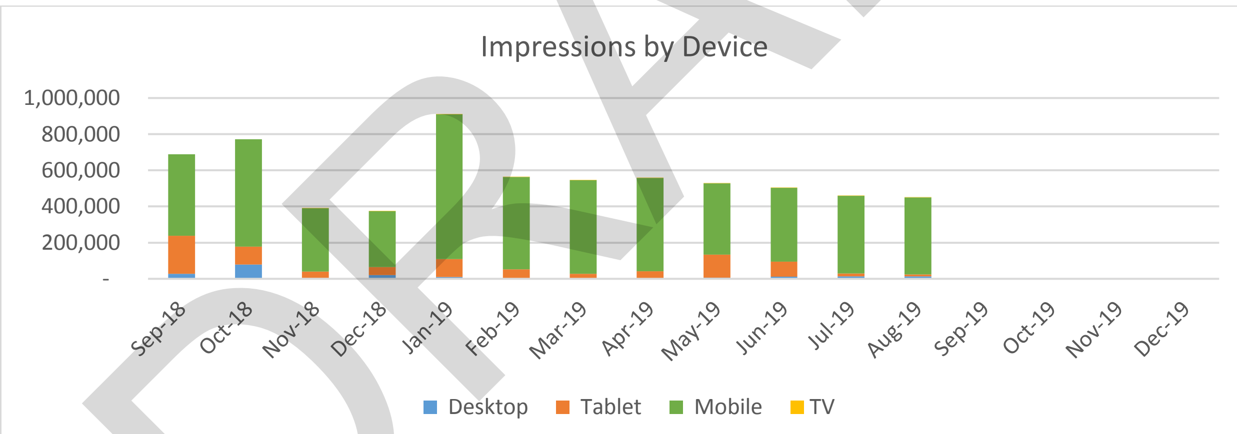
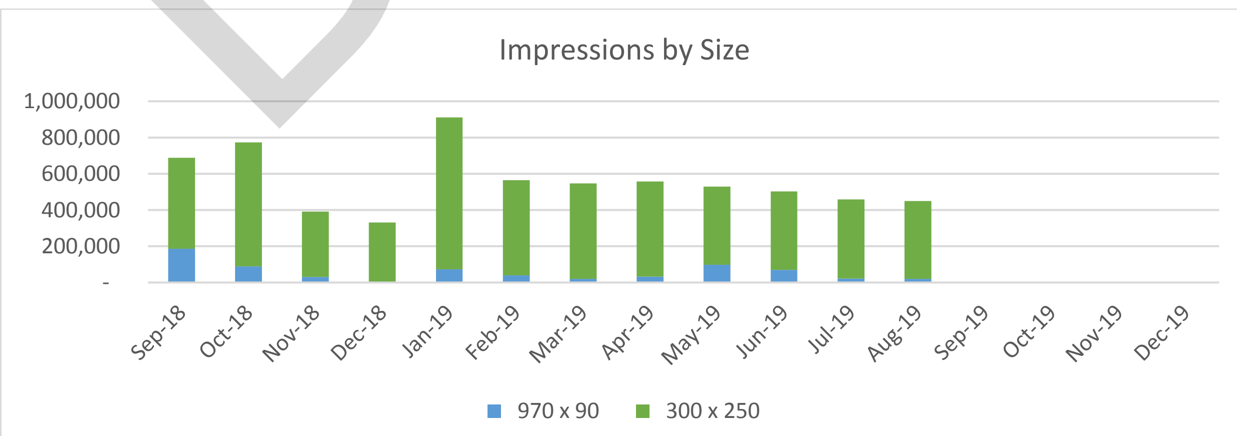
Returning Site Visit	The number of times a unique first-time visitor returns to the website.
Search Engine Optimization (SEO)	The process of maximizing the number of visitors to a website by ensuring that the site appears high on the list of results returned by the search engine.
Total Site Visits	The total number of visits of individuals to a website during a given period. Total site visits are the sum of unique site visits and returning site visits.
Unique Site Visit	The number of visits of distinct individuals to a website during a given period. Does not include the number of revisits that an individual makes to the website.
Webinar	A live, web-based video conference that uses the internet to connect the individual hosting the conference to an audience of viewers. A portmanteau of the terms "web seminar".

Appendix B: Google Adsense Report Data

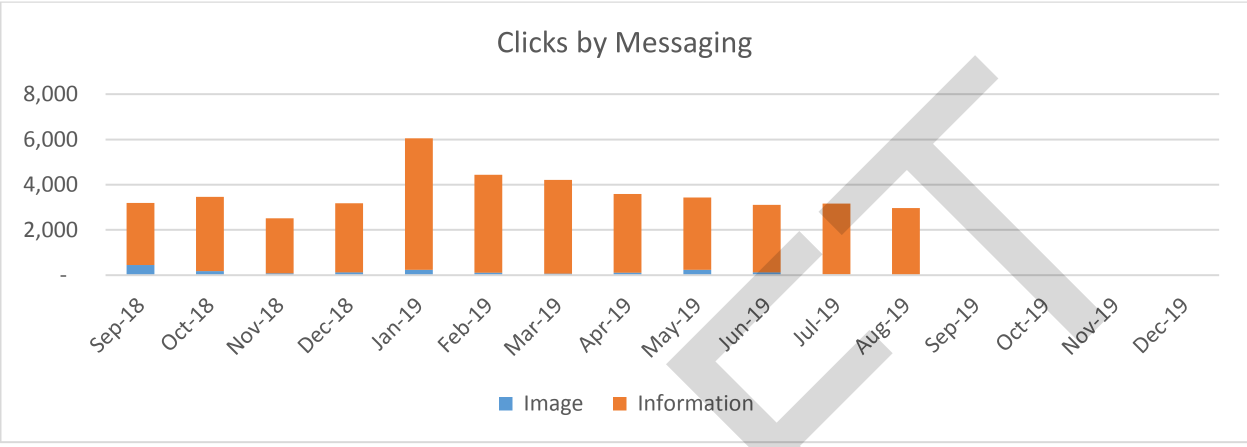
Impressions

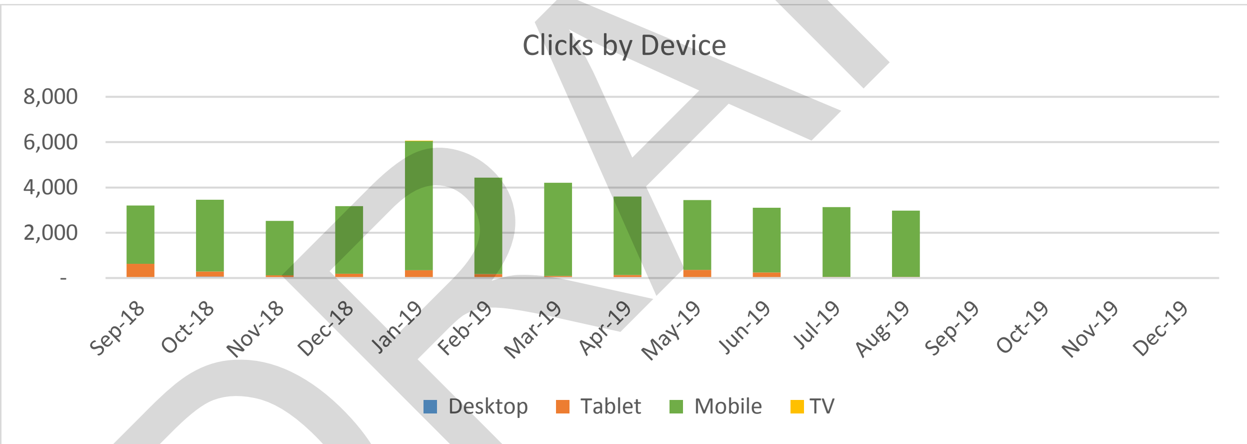


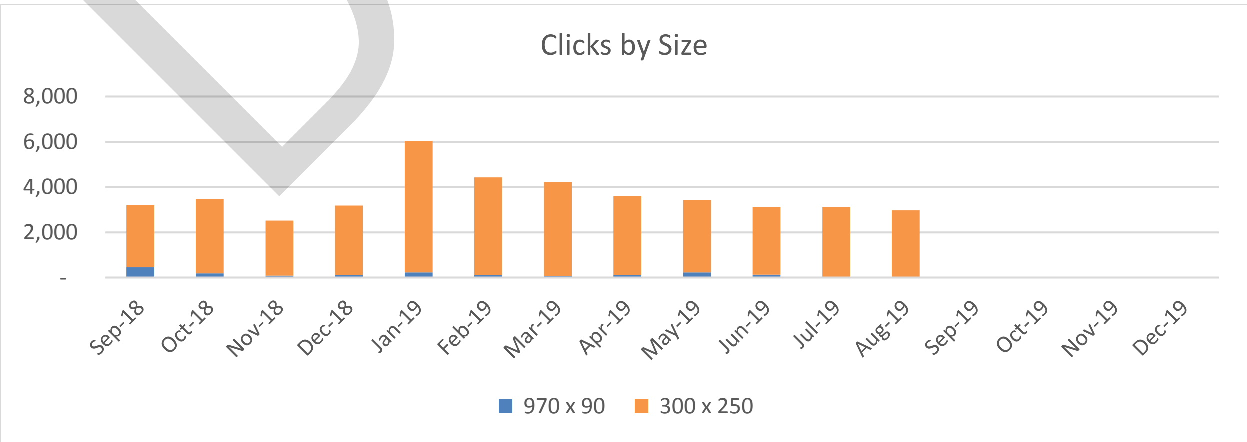




Clicks


Clicks by Messaging
8,000
6,000
4,000
2,000
-
Sep-18 Oct-18 Nov-18 Dec-18 Jan-19 Feb-19 Mar-19 Apr-19 May-19 Jun-19 Jul-19 Aug-19 Sep-19 Oct-19 Nov-19 Dec-19
Image
Information

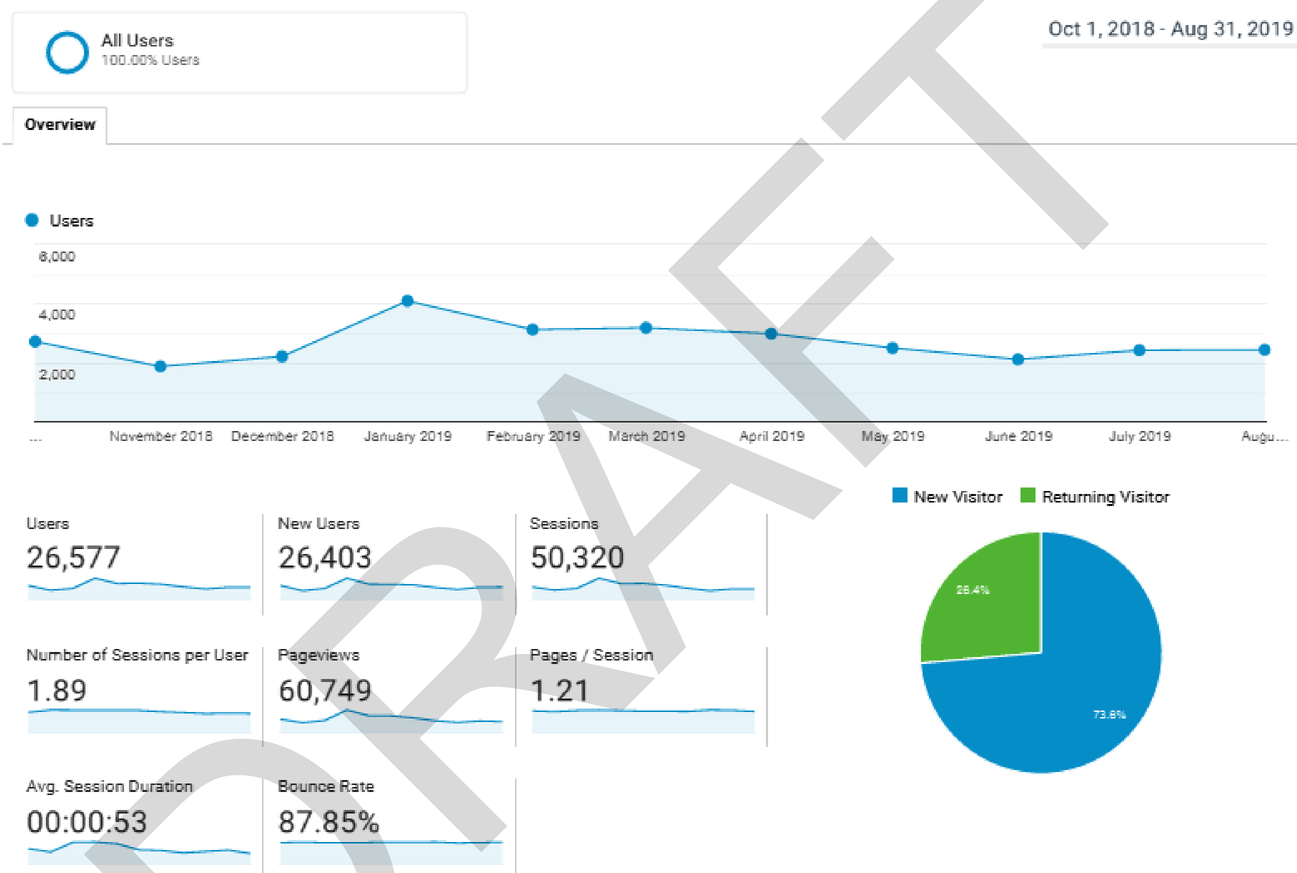

Clicks by Device
8,000
6,000
4,000
2,000
-
Sep-18 Oct-18 Nov-18 Dec-18 Jan-19 Feb-19 Mar-19 Apr-19 May-19 Jun-19 Jul-19 Aug-19 Sep-19 Oct-19 Nov-19 Dec-19
Desktop
Tablet
Mobile
TV


Clicks by Size
8,000
6,000
4,000
2,000
-
Sep-18 Oct-18 Nov-18 Dec-18 Jan-19 Feb-19 Mar-19 Apr-19 May-19 Jun-19 Jul-19 Aug-19 Sep-19 Oct-19 Nov-19 Dec-19
970 x 90
300 x 250

Google Web Rankings

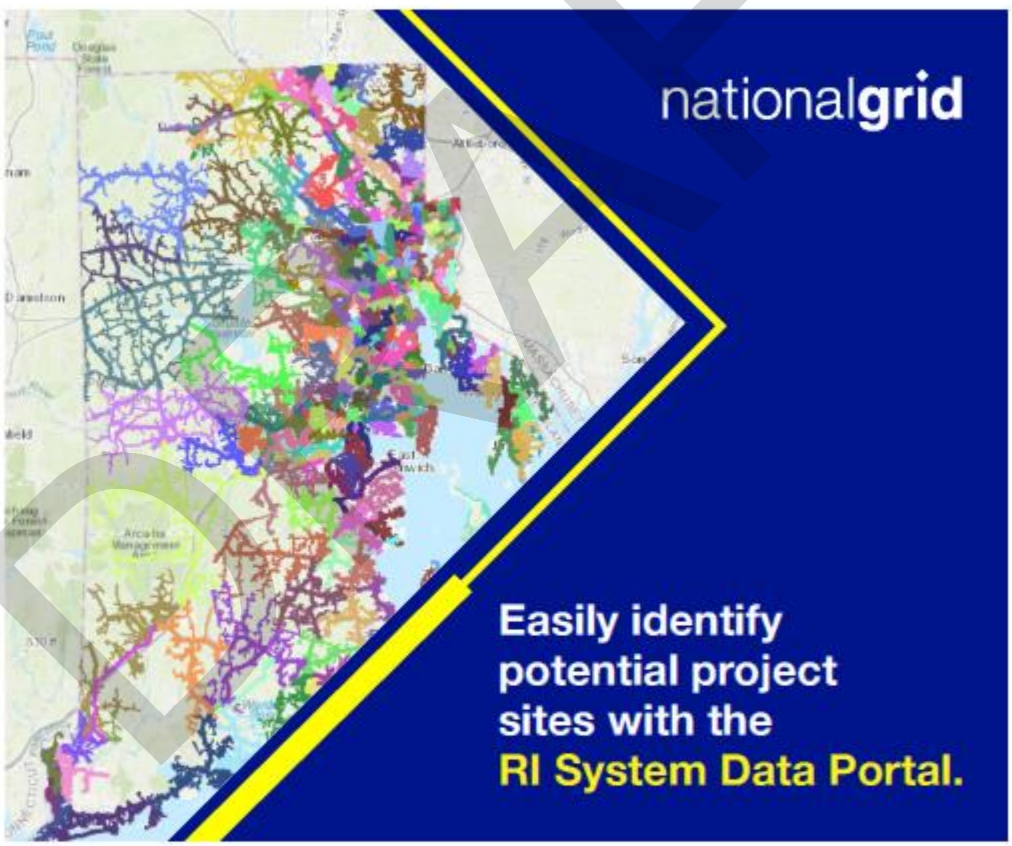
Search Phrase	Google Ranking	Goal
Rhode Island System Data Portal	2	≥ 5
RI System Data Portal	2	≥ 5
National Grid Rhode Island System Data Portal	2	≥ 5
National Grid RI System Data Portal	2	≥ 5

Appendix C: Google Analytics Web Traffic Report



Appendix D: Advertisement Banners

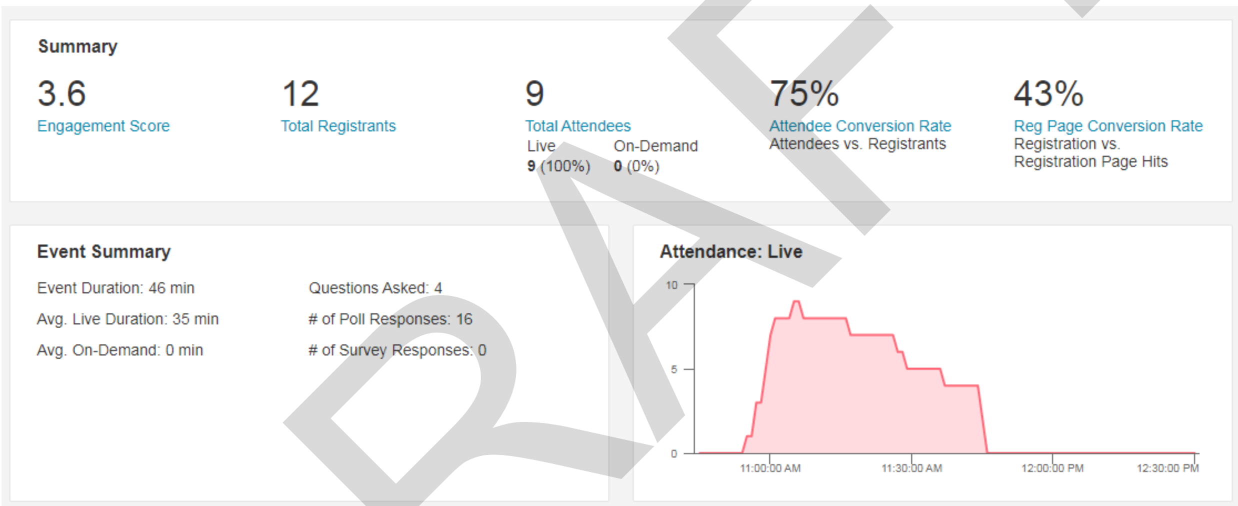
The following two images are the two advertisements used to date as part of marketing the Portal on websites.



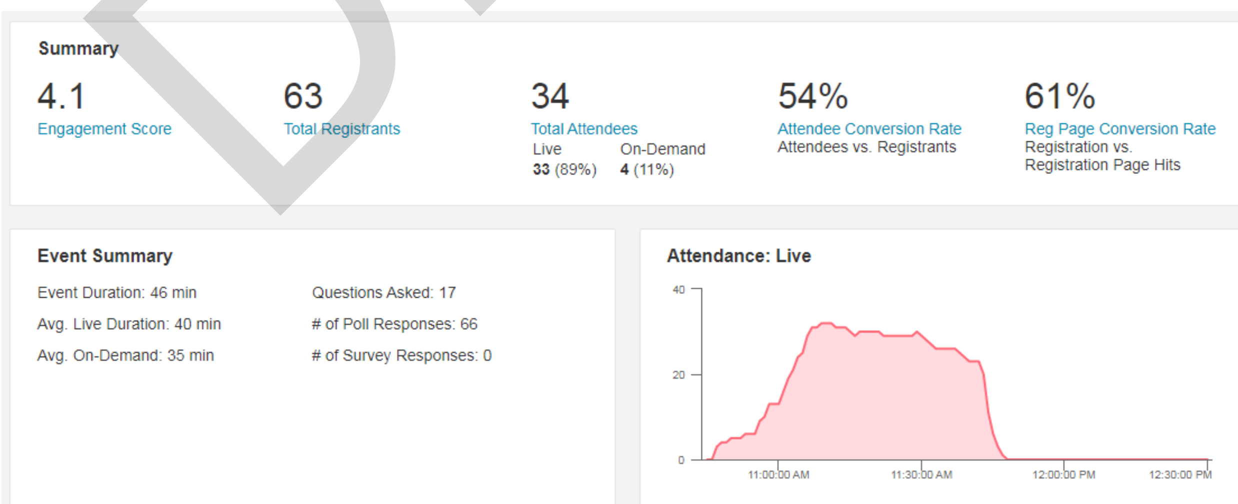
Appendix E: Webinars and Email Marketing

As of August 31st, 2019, the Company has hosted three quarterly webinars to introduce developers and stakeholders to the RI System Data Portal and announce updates to the portal that occurred during the calendar year. As attendance has not met the company's target goals we propose reducing the webinars to two annually in 2020 allowing us to feature any new updates and reach developers who may still be unfamiliar with the portal.

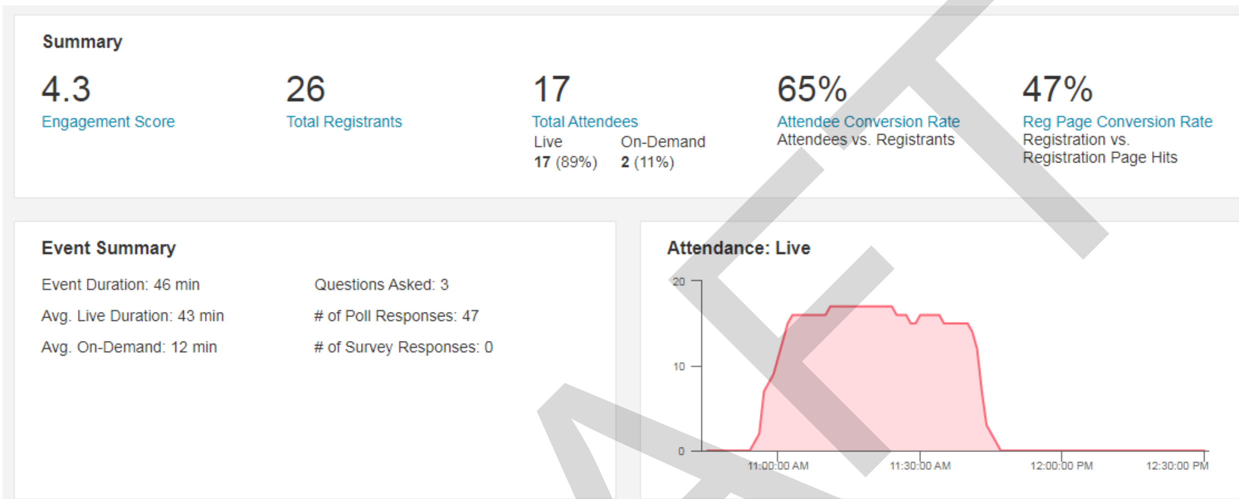
Q1 Webinar Dashboard:



Q2 Webinar Dashboard:



Q3 Webinar Dashboard:



Appendix 7 – 2020 SRP Outreach and Engagement Plan

SYSTEM RELIABILITY PROCUREMENT

2020 SRP Outreach and Engagement Plan

Table of Contents

1. Introduction

The 2020 System Reliability Procurement (SRP) Outreach and Engagement Plan will provide information to the public, with the target audience being third-party solution providers, regarding the status, usefulness, and use-case scenarios of the Rhode Island System Data Portal (Portal).

The Rhode Island System Data Portal is an online, interactive mapping system created for developers to gain visibility to the electric grid distribution system. The Portal contains distribution feeder and substation information including feeder characteristics such as geographic locations, voltage, feeder ID, planning area, substation source as well as loading and available distribution generation hosting capacity. The Portal went live on June 30, 2018 and is a new digital asset of National Grid[1] for use by third-party solution providers.

There may be additional opportunities for installations of alternative solutions and technologies that reduce peak load outside of National Grid's consideration and proposal of cost-effective Non-Wires Alternative (NWA) projects. An SRP Outreach and Engagement Plan will nurture these inherent opportunities with the work the Company is doing on the Portal, and to encourage and engage Distributed Energy Resource (DER) solution providers to support the strategic deployment of these solutions to benefit constrained areas.

Such engagement will enable third-party solution providers and vendors to more easily access available information about National Grid's electric distribution system in Rhode Island and therefore further enable these solution providers to create, submit and develop innovative energy solutions for Rhode Island customers. The SRP Outreach and Engagement Plan upholds the commitment of National Grid and the State of Rhode Island to advance a more reliable, safe, and cost-effective energy landscape for residents and businesses of Rhode Island.

The Company proposes the 2020 SRP Outreach and Engagement Plan to promote the Portal and associated resources described in the annual System Reliability Procurement Reports as they exist and are developed.

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

2. Purpose

The purpose of the SRP Outreach and Engagement Plan is to raise awareness of and drive engagement with the Rhode Island System Data Portal and associated map resources to all appropriate Rhode Island parties, with the primary target audience being third-party solution providers.

3. Timeline

The 2020 SRP Outreach and Engagement Plan will take place during calendar year 2020, effectively starting on January 1 and ending on December 31.

4. Program Budget

The budget for SRP Outreach and Engagement is $69,370 to support this initiative in 2020.
The Company will need funding to support the creation and dissemination of marketing materials and tracking mechanisms and for marketing vendor payment. This is captured in the Materials and Vendors category in the table below.

The Company will need funding to support program planning and administration, which is associated with the management of materials development within the Company and with vendors and of the tracking and evaluation processes to determine the initiative's effectiveness. This is captured in the Program Planning and Administration category in the table below.

Table 1: SRP Market Engagement Funding Plan

Category	**Cost**
Materials and Vendors	$41,370
Program Planning and Administration	$28,000
Total	**$69,370**

Please note that this budget does not include funding associated with marketing for other programs such as RE Growth, Connected Solutions, and EE. The budget for the SRP Outreach and Engagement Plan only accounts for outreach and engagement efforts with respect to the Rhode Island System Data Portal.

5. Outreach Channels

This section provides an overview of the primary business-to-business (B2B) outreach and engagement channels National Grid plans to implement through the SRP Outreach and Engagement Plan for calendar year 2020 to engage with third-party solution providers.

5.1 Webinars

National Grid plans on presenting in-depth technical web-based walkthroughs in webinars. Webinar events and hosting will be coordinated by a third-party marketing vendor, with National Grid employees providing the walkthrough, question response, and content.

Webinars connect National Grid with third-party solution providers, provide these vendors with pertinent information and guidance on how to use the Portal, and provide an open forum for questions and answers.

National Grid plans to provide two webinars throughout the calendar year, with one performed each half year. Additional webinars may be held as needed depending on any major updates made to the Portal in calendar year 2020.

5.2 In-Person Demonstrations

National Grid plans on presenting in-depth technical in-person demonstrations. In-person demonstrations will be coordinated and hosted by National Grid.

In-person demonstrations are similar to webinars in purpose, with the added benefit that hands-on guidance can be provided to the vendor during the demonstration.

National Grid plans to provide two in-person demonstrations, with one performed per half year for calendar year 2020. Additional in-person demonstrations may be held as needed depending on external stakeholder or vendor meeting and event opportunities.

5.3 Email

National Grid plans on performing email outreach to third-party solution providers. Email campaigns will be coordinated and delivered by a third-party marketing vendor.

Email marketing helps to maintain and raise awareness for current and new vendors, notify vendors of any major changes or updates to the Portal, and impresses upon vendors that the Portal is a useful tool to use as part of project and proposal development.

National Grid plans on performing four email campaigns, with one campaign performed per quarter, to maintain awareness of the Portal among the current vendor base. Additional email marketing to National Grid's vendors will occur as needed for major updates. Email marketing for any new vendors will occur as needed to welcome and onboard the new vendors.

5.4 Digital Advertisements

National Grid plans on continuing digital advertisements through calendar year 2020. National Grid will work with a third-party marketing vendor to place digital advertisements.

Digital advertisement placements generate awareness for third-party solution providers overall. Digital advertisements have the added benefit of generating awareness for vendors who are not yet in National Grid's vendor list and therefore aren't receiving emails or webinar/demo notifications.

5.5 Paid Search Terms

National Grid plans to continue the paid web search terms strategy through calendar year 2020. National Grid will work with a third-party marketing vendor to effectuate paid search terms to market the Portal by Search Engine Optimization (SEO) with search engine keywords by paying to prioritize the Portal in identified searches via engines like Google, Yahoo, Microsoft Bing, etc. Search Engine Optimization is the process of maximizing the number of visitors to a website by ensuring that the site appears high on the list of results returned by the search engine.

Paid search terms enable the Portal to be populated much higher in a web search results list. This search result improvement allows vendors to more easily receive search results relevant to the Portal. A web search is another venue where new vendors can find out about the Portal through the use of related terminology.

5.6 Social Media Engagement

National Grid plans to post updates on the Company pages of LinkedIn to enable another venue of outreach to new and existing vendors. National Grid will create and manage these posts directly.

Posting important updates on a business-oriented social media platform will help to maintain awareness of the Portal and to concisely call out important changes to the Portal for vendors.

5.7 Feedback Engagement

In addition to receiving feedback in the webinars and in-person demonstrations, National Grid plans to host one focus group during calendar year 2020 for vendor stakeholders to provide enhanced feedback and in-depth discussion regarding the Portal.

National Grid also plans to send two in-depth feedback surveys to vendor stakeholders in calendar year 2020 as part of the email campaigns described in Section 5.3.

5.8 Earned Media

National Grid plans to explore developing strategic articles to place in appropriate industry and trade publications. Publishing industry articles will help highlight the Portal and its purpose to vendors in an additional channel to email and web outreach.

5.9 Vendor Contact List

National Grid plans to procure contact lists of vendors to expand the Company's scope of outreach to new vendors. Vendor contact lists are available from third-party outreach vendors. Procuring a vendor contact list will enable National Grid to directly contact vendors, especially new vendors, who are not currently being reached via email marketing or web advertisements.

5.10 Contact Channels

National Grid plans to create a dedicated email distribution list for all appropriate inquiries related to the Portal. National Grid also plans to coordinate existing email distribution lists on the Portal so that vendors can optimally communicate with the topically-corresponding internal team.

6. Outreach Performance Evaluation

National Grid will continuously monitor, track, and assess the effectiveness of the 2020 SRP Outreach and Engagement Plan.

In order to achieve the purpose of the SRP Outreach and Engagement Plan, the outreach efforts are to meet or exceed the goals outlined in this section.

National Grid will use the following performance metrics and goals for SRP Outreach and Engagement Plan evaluation:

6.1 Webinars

Attendance: Achieve average webinar attendance greater than or equal to 35. There is no industry average benchmark because webinar attendance varies per event and topical substance.

6.2 Email

Open Rate: Achieve an average email open rate greater than or equal to 15% for email campaigns. The industry average email open rate benchmark is 15%.

6.3 Digital Advertisements

1. **Ad Impressions**: Achieve average ad impressions greater than or equal to 400,000 for digital advertisements. There is no industry average benchmark for ad impressions because impressions vary based on budget.
2. **Click-Through Rate (CTR)**: Achieve an average CTR greater than or equal to 0.60% for digital advertisements. The industry average CTR benchmark is 0.40%.

6.4 Paid Search Terms

Web Rankings: Maintain the Rhode Island System Data Portal in the top five web search results for our top-performing paid search terms. (The Portal will be returned as one of the top five search results when a top-performing paid search term is used.) The industry standard for Search Engine Optimization (SEO) is for rankings to appear “above the fold”, or on page one of the search results.

6.5 Web Traffic

Total Site Visits: Achieve average total site visits greater than or equal to 1,500. There is no industry standard for web traffic specific to one designated landing page.

Table 2: Outreach Performance Evaluation Goals

Outreach Channel	Corresponding Metric	Goals
Webinars	Attendance	Average Attendance ≥ 35
Email Outreach	Open Rate	Average Open Rate ≥ 15%
Digital Advertisements	Click-Through Rate (CTR)	Average CTR ≥ 0.60%
Digital Advertisements	Ad Impressions	Average Ad Impressions ≥ 400k
Paid Search Terms	Web Rankings	Web Rankings ≥ 5^{th}
Web Traffic	Total Site Visits	Average Total Site Visits ≥ 1,500

7. Appendix A: Table of Terms

Below is a table to help provide clarity on the marketing and related terms.

Term	Definition
Clicks	The number of times an individual selects or clicks on an advertisement or its equivalent.
Click-Through Rate (CTR)	The rate of clicks per impression, calculated by clicks divided by impressions. This represents, in part, the percentage of times users have clicked on a banner.
Digital Ad Placements	A specific group of advertisements on which an advertiser can choose to place their ads using placement targeting. A digital placement is one that takes place on digital media, such as the internet.
Impressions	The number of times an advertisement was viewed.
Non-Wires Alternative (NWA)	The inclusive term for any electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment".
Open Rate	The percentage of people who opened an email out of the total number of recipients. This number will include people who opened the email more than once. An indicator of subject line success and topic relevance.
Paid Search Term	A phrase or word on which advertisers bid to trigger their website or webpage to be shown to relevant users, dependent on term used.
Rankings	The position of a website or webpage in a search result list, dependent on the term used in the search engine.
Returning Site Visit	The number of times a unique first-time visitor returns to the website.
Search Engine Optimization (SEO)	The process of maximizing the number of visitors to a website by ensuring that the site appears high on the list of results returned by the search engine.
Total Site Visits	The total number of visits of individuals to a website during a given period. Total site visits are the sum of unique site visits and returning site visits.
Unique Site Visit	The number of visits of distinct individuals to a website during a given period. Does not include the number of revisits that an individual makes to the website.
Webinar	A live, web-based video conference that uses the internet to connect the individual hosting the conference to an audience of viewers. A portmanteau of the terms "web seminar".

Appendix 8 – Narragansett 42F1 NWA RFP

National Grid USA Service Company, Inc.

Request for Proposals (RFP)

Non-Wires Alternative Project to Provide Solutions for the Distribution System in Narragansett, Rhode Island (Feeder 42F1)

ISSUED: DECEMBER 13, 2018
SUBMISSION DEADLINE: FEBRUARY 11, 2019

nationalgrid

Table of Contents

1. Introduction

National Grid is a gas and electric investor-owned utility serving nearly 3.3 million electric and 3.5 million gas customers through its subsidiary companies in Massachusetts, New York, and Rhode Island.

National Grid is committed to providing safe, reliable, and affordable energy to all customers throughout our service territory. As a part of providing this service, National Grid is pursuing the potential implementation of Non-Wires Alternative (NWA) solutions in Rhode Island. Such implementation aligns with principles set forth by the RI PUC Title 39 § 39-1-27.7 – System Reliability and Least-Cost Procurement.

National Grid has been pursuing Non-Wires Alternative projects across its service territories for several years.

2. Definition of NWA

Non-Wires Alternative (NWA), sometimes referred to as Non-Wires Solution (NWS), is the inclusive term for any electrical grid investment that is intended to defer or remove the need for traditional equipment upgrades or construction, or "wires investment", to distribution and/or transmission systems.

These NWA investments are required to be cost-effective compared to the traditional wires investment and are required to meet the specified electrical grid need.

An NWA can include any action, strategy, program, or technology that meets this definition and these requirements.

Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs). NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

3. Our Goal

This RFP seeks to identify technologies and/or methodologies that, if implemented, will provide an NWA solution for a geographical area that has an electrical grid need. This area and need are identified in Section 4 – Project Overview.

This RFP is open to all NWA approaches. This RFP is meant to assess the best-fit technology type for this NWA project.

Any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2024 and operating until at least 2030. Any NWA solutions that exceed this timeline will also be considered. Please note that National Grid is seeking solutions that currently exist to solve the stated need.

Proposed technologies and methodologies should have the capability to address the electrical grid need and increase grid reliability while being cost-effective in comparison to the traditional wires investment. Proposed technologies and methodologies should also be available when needed and respond immediately when called upon for the duration of NWA solution implementation.

To assist qualified bidders this document provides an overview of the project objectives, detailed business requirements and response submission information.

As outlined in the RFP Schedule section of this document, bidders will have the opportunity to submit questions that assist in creating a response for this initiative. Please see the RFP Timeline Schedule for dates associated with RFP milestones below.

4. Project Overview

Potential for Non-Wires Alternative Project in Narragansett, RI

4.1. Background

The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings by 2021 and lack useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town. Both a wires and a non-wires option was developed to address these projected overloads.

- **Wires Option:** Upgrade the Wakefield 17F2 feeder and modify the 17F3 feeder. This investment increases capacity and switching flexibility to relieve the heavily loaded facilities and resolves the projected overloads.
- **Non-Wires Option:** See Sections 4.1 and 4.2 below for Non-Wires requirements.

4.2. Technical Requirements

Problem Statement						
Description	The Company is seeking to provide load relief for the Bonnet 42F1 feeder.					
Technical Information	Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
	Bonnet	42F1	12.47 kV	525	2024	2070

Solution Requirements	
Technical Requirements	Maintain feeder loading below 90% of summer normal rating over a ten-year period by proposing a NWA solution that reduces loading on the feeder by 2070kW through 2030.
In Service Date	2024
Maximum MWHr need	Based on historic data 23 MWhrs total over the course of a year by 2030.
Lifetime	10 years minimum
Call Response Time	24 hours
Days of the Week needed	Any days that the day-ahead ISO-NE load forecast applied to the Project Feeders indicates that loading will exceed 90% of the Feeder Summer normal rating. This could be both weekdays and weekends.
Time of Day	Any time of day.
Number of Time Called Per Year	A minimum of 5 days based on historic data In order to account for the potential of a heat wave, the project may be called for 5 or more days in a row during peak load times.
Minimum Period between Calls	24 hours


42F1 Feeder Mainline
Bonnet Substation
Narrow River
S Ferry Rd
BONNET SHORES
Middlebridge Rd
Bonnet Point Rd
Colonel John Gardner Rd
Narragansett
Narragansett Town Beach
DRAFT

Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.

NOTE: Subject to changes in forecasted needs, solution pricing, as well as any other applicable costs and benefits, National Grid is targeting to procure demand response and/or generation/storage that could supply the substation(s) load in its entirety or a large portion of it. During normal operation, any excess power could be exported to the National Grid System. Depending on such factors as economics, portfolio fit, etc.

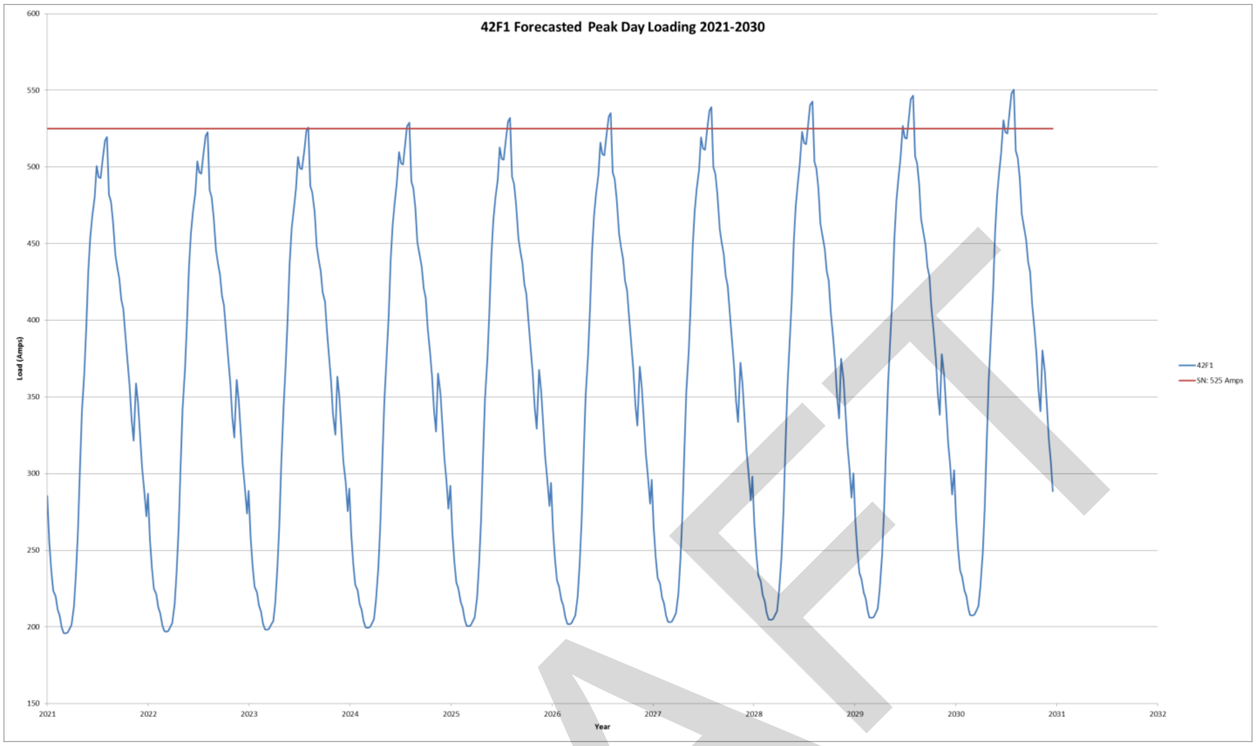
4.3. Technical Details

Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
Bonnet	42F1	12.47 kV	525	2024	2070

Substation	Feeder	Commercial Customers	Residential Customers	Total
Bonnet	42F1	184	2714	2898

4.3.1. Feeder Loading

Loading on the 42F1 and 17F2 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded over the next ten years. All other facilities' loadings are within their normal equipment ratings. The rating of feeders is determined by the equipment with the most limiting element (that with the lowest normal summer rating). The load forecast utilizes a technique called weather normalization, a process that assumes future year peaks will occur given high loading condition (e.g., a June peak will occur on hot day, where the temperature in the 95th percentile of hottest years). The charts below show the projected load on the feeders using the peak day at the time of study and the loads are grown according to the forecasted analysis.



4.4. Solution Timeline

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2024.

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset until at least 2030. Any NWA solutions that exceed this timeline will also be considered.

5. Project Cost

National Grid is seeking solutions that provide value to the customer and are cost-effective.

The NWA solution shall have a total cost not to exceed a Net Present Value (NPV) of $336,800, based on traditional distribution asset deferral until at least 2030.

National Grid is open to considering shared capital costs or owning a non-generation solution or asset.

National Grid encourages vendors to participate in relevant external revenue streams to produce the most cost-effective solution.

Pricing models to be considered shall be as follows:

- Capital Expenditure
- Annual service fee
- Energy Services Agreement for capacity delivered (i.e., dollars per kW)
- Any combination of the above

6. Instructions for Bidders

6.1. Response and Deliverables

This section describes the list of items and deliverables required from the bidder. Please provide detail in your response as to why the technology/solution your firm proposes is the best-fit for this NWA project. All items should be responded to in the context of the project listed in Section 4 – Project Overview.

Please provide a concise written response under 15 pages (excluding appendices) for ease of review. There will be sections to upload additional documents on the Ariba Platform.

Responses that do not provide the requested information below can be disqualified. Bidders must submit their responses in the following format.

- Executive Summary of Proposed Technology/Solution
- Financial Plan
    - Cost of Technology/Solution for the Specified Need
    - Cost comparison to other technologies/solutions
    - Bidder's Suggested Financial Plan
- Implementation of Technology/Solution
    - Technology/Solution Reliability, with Documentation on the Solution's Technical Reliability
    - Examples of Firm's Application of Technology/Solution
- Timeline for Technology/Solution Installation
- Bidder Qualifications (To be included as an Appendix)

Bidders must additionally provide the following as an Appendix/Attachment:

- List of Historical Project Permits
- Historical Safety Record
- List of Current Environmental Certifications
- List of Historical Project Environmental/Eco awards

6.2. Submittal Requirements

Submittal requirements for this NWA RFP are as follows:

- Overall proposal document as detailed in Section 6.1.
- Pricing Model spreadsheet as provided in the Ariba platform.

6.3. Evaluation Criteria

This section describes the evaluation criteria that project bid responses will be screened with.

- Cost
- Scalability
- Load Reduction Capability
- Feasibility of Proposed Technology Type/Solution
- Risk of Proposed Technology Type/Solution Creating Negative System Impacts
- Environmental or "Green" Requirement

6.4. RFP Schedule

- RFP Launch: 12/7/2018
- Bidders Conference Call: 12/17/2018
- Last date to submit questions: 1/18/2019
- Responses Due: 2/11/2019

6.5. Rhode Island System Data Portal

National Grid has developed a new web-based tool called the Rhode Island System Data Portal that houses a collection of maps to help customers, contractors, and developers identify potential project sites and with project bidding and development. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid electric service area in Rhode Island.

The Rhode Island System Data Portal can be found at the following location:

https://www.nationalgridus.com/Business-Partners/RI-System-Portal

Appendix 9 – Narragansett 17F2 NWA RFP

National Grid USA Service Company, Inc.

Request for Proposals (RFP)

Non-Wires Alternative Project to Provide Solutions for the Distribution System in Narragansett, Rhode Island (Feeder 17F2)

ISSUED: DECEMBER 13, 2018
SUBMISSION DEADLINE: FEBRUARY 11, 2019

nationalgrid

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These NWA investments are required to be cost-effective compared to the traditional wires investment and are required to meet the specified electrical grid need.

An NWA can include any action, strategy, program, or technology that meets this definition and these requirements.

Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs). NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

3. Our Goal

This RFP seeks to identify technologies and/or methodologies that, if implemented, will provide an NWA solution for a geographical area that has an electrical grid need. This area and need are identified in Section 4 – Project Overview.

This RFP is open to all NWA approaches. This RFP is meant to assess the best-fit technology type for this NWA project.

Any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2021 and operating until at least 2030. Any NWA solutions that exceed this timeline will also be considered. Please note that National Grid is seeking solutions that currently exist to solve the stated need.

Proposed technologies and methodologies should have the capability to address the electrical grid need and increase grid reliability while being cost-effective in comparison to the traditional wires investment. Proposed technologies and methodologies should also be available when needed and respond immediately when called upon for the duration of NWA solution implementation.

To assist qualified bidders this document provides an overview of the project objectives, detailed business requirements and response submission information.

As outlined in the RFP Schedule section of this document, bidders will have the opportunity to submit questions that assist in creating a response for this initiative. Please see the RFP Timeline Schedule for dates associated with RFP milestones below.

4. Project Overview

<u>Potential for Non-Wires Alternative Project in Narragansett, RI</u>

4.1. Background

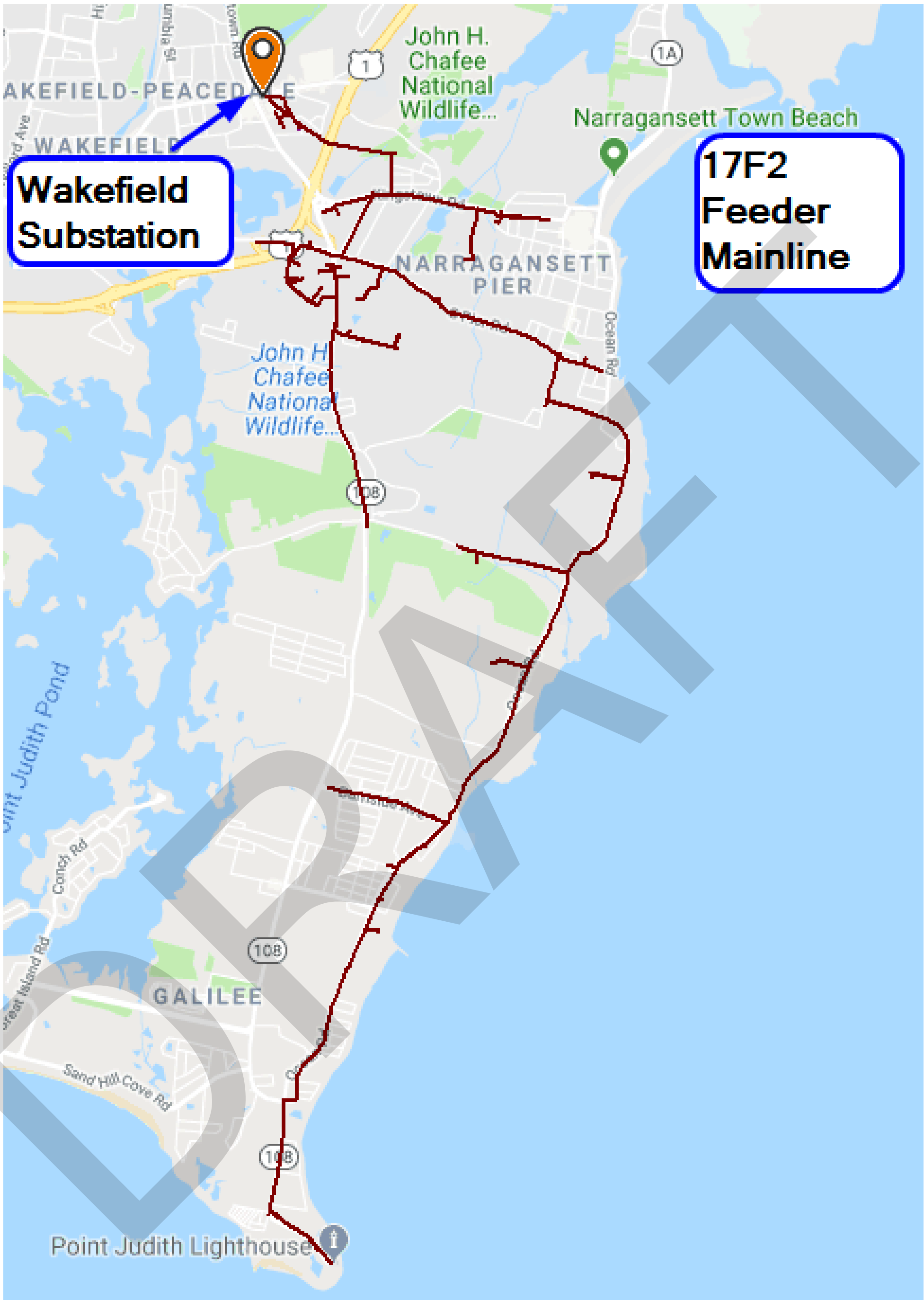
The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings by 2021 and lack useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town. Both a wires and a non-wires option was developed to address these projected overloads.

- **Wires Option:** Upgrade the Wakefield 17F2 feeder and modify the 17F3 feeder. This investment increases capacity and switching flexibility to relieve the heavily loaded facilities and resolves the projected overloads.
- **Non-Wires Option:** See Sections 4.1 and 4.2 below for Non-Wires requirements.

4.2. Technical Requirements

Problem Statement						
Description	The Company is seeking to provide load relief for the Wakefield Substation 17F2 feeder.					
Technical Information	**Substation**	**Feeder**	**Operating Voltage**	**Summer Normal Rating (Amps)**	**Overloaded By**	**Load Reduction Needed (kW)**
	Wakefield	17F2	12.47 kV	510	2021	1,794

Solution Requirements	
Technical Requirements	Maintain feeder loading below 90% of summer normal rating over a ten-year period by proposing a NWA solution that reduces loading on the feeder by 1,794kW through 2030.
In Service Date	2021
Maximum MWHr need	Based on historic data 76 MWhrs total over the course of a year by 2030.
Lifetime	10 years minimum
Call Response Time	24 hours
Days of the Week needed	Any days that the day-ahead ISO-NE load forecast applied to the Project Feeders indicates that loading will exceed 90% of the Feeder Summer normal rating. This could be both weekdays and weekends.
Time of Day	Any time of day.
Number of Time Called Per Year	A minimum of 14 days based on historic data In order to account for the potential of a heat wave, the project may be called for 5 or more days in a row during peak load times.
Minimum Period between Calls	24 hours



Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.

NOTE: Subject to changes in forecasted needs, solution pricing, as well as any other applicable costs and benefits, National Grid is targeting to procure demand response and/or generation/storage that could supply the substation(s) load in its entirety or a large portion of it. During normal operation, any excess power could be exported to the National Grid System. Depending on such factors as economics, portfolio fit, etc.

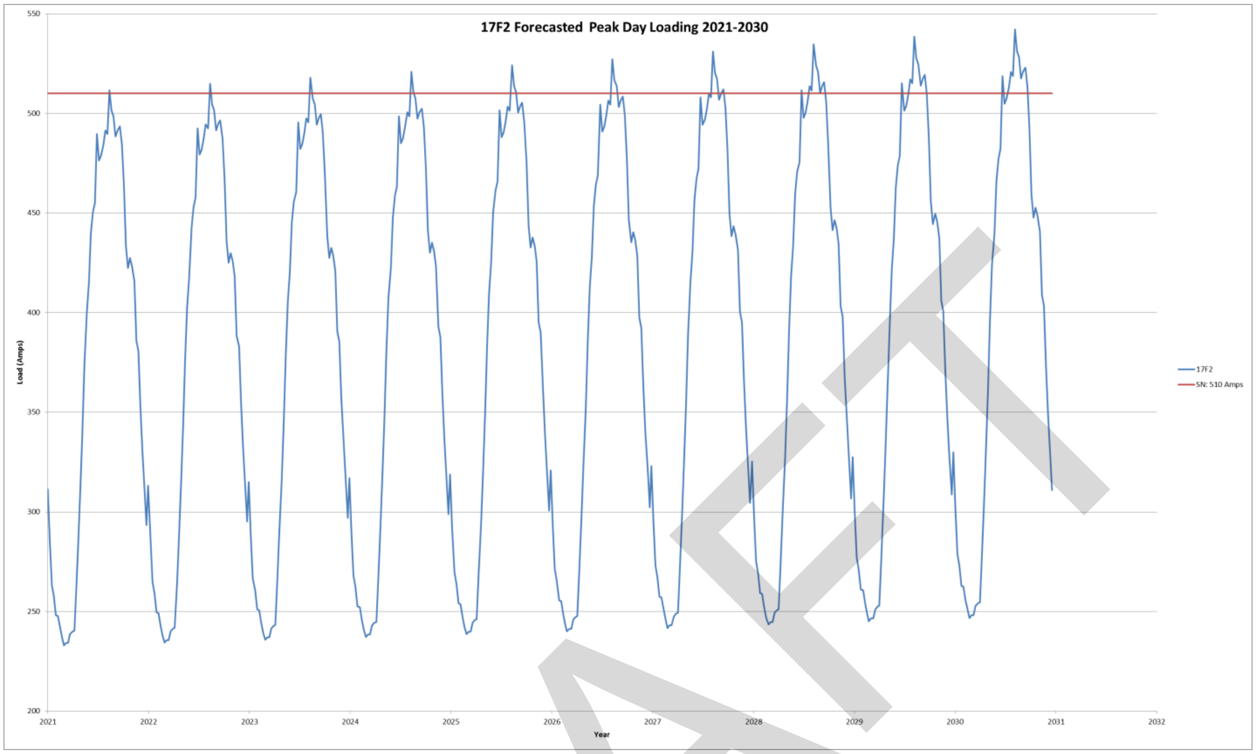
4.3. Technical Details

Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
Wakefield	17F2	12.47 kV	510	2021	1,794

Substation	Feeder	Commercial Customers	Residential Customers	Total
Wakefield	17F2	221	2679	2900

4.3.1. Feeder Loading

Loading on the 42F1 and 17F2 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded over the next ten years. All other facilities' loadings are within their normal equipment ratings. The rating of feeders is determined by the equipment with the most limiting element (that with the lowest normal summer rating). The load forecast utilizes a technique called weather normalization, a process that assumes future year peaks will occur given high loading condition (e.g., a June peak will occur on hot day, where the temperature in the 95th percentile of hottest years). The charts below show the projected load on the feeders using the peak day at the time of study and the loads are grown according to the forecasted analysis.



4.4. Solution Timeline

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2021.

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset until at least 2030. Any NWA solutions that exceed this timeline will also be considered.

5. Project Cost

National Grid is seeking solutions that provide value to the customer and are cost-effective.

The NWA solution shall have a total cost not to exceed a Net Present Value (NPV) of $572,200, based on traditional distribution asset deferral until at least 2030.

National Grid is open to considering shared capital costs or owning a non-generation solution or asset.

National Grid encourages vendors to participate in relevant external revenue streams to produce the most cost-effective solution.

Pricing models to be considered shall be as follows:

- Capital Expenditure
- Annual service fee
- Energy Services Agreement for capacity delivered (i.e., dollars per kW)
- Any combination of the above

6. Instructions for Bidders

6.1. Response and Deliverables

This section describes the list of items and deliverables required from the bidder. Please provide detail in your response as to why the technology/solution your firm proposes is the best-fit for this NWA project. All items should be responded to in the context of the project listed in Section 4 – Project Overview.

Please provide a concise written response under 15 pages (excluding appendices) for ease of review. There will be sections to upload additional documents on the Ariba Platform.

Responses that do not provide the requested information below can be disqualified. Bidders must submit their responses in the following format.

- Executive Summary of Proposed Technology/Solution
- Financial Plan
    - Cost of Technology/Solution for the Specified Need
    - Cost comparison to other technologies/solutions
    - Bidder's Suggested Financial Plan
- Implementation of Technology/Solution
    - Technology/Solution Reliability, with Documentation on the Solution's Technical Reliability
    - Examples of Firm's Application of Technology/Solution
- Timeline for Technology/Solution Installation
- Bidder Qualifications (To be included as an Appendix)

Bidders must additionally provide the following as an Appendix/Attachment:

- List of Historical Project Permits
- Historical Safety Record
- List of Current Environmental Certifications
- List of Historical Project Environmental/Eco awards

6.2. Submittal Requirements

Submittal requirements for this NWA RFP are as follows:

- Overall proposal document as detailed in Section 6.1.
- Pricing Model spreadsheet as provided in the Ariba platform.

6.3. Evaluation Criteria

This section describes the evaluation criteria that project bid responses will be screened with.

- Cost
- Scalability
- Load Reduction Capability
- Feasibility of Proposed Technology Type/Solution
- Risk of Proposed Technology Type/Solution Creating Negative System Impacts
- Environmental or "Green" Requirement

6.4. RFP Schedule

- RFP Launch: 12/7/2018
- Bidders Conference Call: 12/17/2018
- Last date to submit questions: 1/18/2019
- Responses Due: 2/11/2019

6.5. Rhode Island System Data Portal

National Grid has developed a new web-based tool called the Rhode Island System Data Portal that houses a collection of maps to help customers, contractors, and developers identify potential project sites and with project bidding and development. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid electric service area in Rhode Island.

The Rhode Island System Data Portal can be found at the following location:

https://www.nationalgridus.com/Business-Partners/RI-System-Portal

Appendix 10 – South Kingstown NWA RFP

National Grid USA Service Company, Inc.

Request for Proposals (RFP)

Non-Wires Alternative Project to Provide Solutions for the Distribution System in South Kingstown, Rhode Island

ISSUED: JANUARY 29, 2019
REVISION ISSUED: FEBRUARY 22, 2019
SUBMISSION DEADLINE: APRIL 23, 2019

nationalgrid

Table of Contents

1. Introduction

National Grid is a gas and electric investor-owned utility serving nearly 3.3 million electric and 3.5 million gas customers through its subsidiary companies in Massachusetts, New York, and Rhode Island.

National Grid is committed to providing safe, reliable, and affordable energy to all customers throughout our service territory. As a part of providing this service, National Grid is pursuing the potential implementation of Non-Wires Alternative (NWA) solutions in Rhode Island. Such implementation aligns with principles set forth by the RI PUC Title 39 § 39-1-27.7 – System Reliability and Least-Cost Procurement.

National Grid has been pursuing Non-Wires Alternative projects across its service territories for several years.

2. Definition of NWA

Non-Wires Alternative (NWA), sometimes referred to as Non-Wires Solution (NWS), is the inclusive term for any electrical grid investment that is intended to defer or remove the need for traditional equipment upgrades or construction, or “wires investment”, to distribution and/or transmission systems.

These NWA investments are required to be cost-effective compared to the traditional wires investment and are required to meet the specified electrical grid need.

An NWA can include any action, strategy, program, or technology that meets this definition and these requirements.

Some technologies and methodologies that can be applicable as an NWA investment include demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (DERs). NWA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

3. Our Goal

This RFP seeks to identify technologies and/or methodologies that, if implemented, will provide an NWA solution for a geographical area that has an electrical grid need. This area and need are identified in Section 4 – Project Overview.

This RFP is open to all NWA approaches. This RFP is meant to assess the best-fit technology type for this NWA project.

Any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2022 and operating until at least 2030. Any NWA solutions that exceed this timeline will also be considered. Please note that National Grid is seeking solutions that currently exist to solve the stated need.

Proposed technologies and methodologies should have the capability to address the electrical grid need and increase grid reliability while being cost-effective in comparison to the traditional wires investment. Proposed technologies and methodologies should also be available when needed and respond immediately when called upon for the duration of NWA solution implementation.

To assist qualified bidders this document provides an overview of the project objectives, detailed business requirements and response submission information.

As outlined in the RFP Schedule section of this document, bidders will have the opportunity to submit questions that assist in creating a response for this initiative. Please see the RFP Timeline Schedule for dates associated with RFP milestones below.

4. Project Overview

Potential for Non-Wires Alternative Project in South Kingstown, RI

4.1. Background

The western section of the Town of South Kingstown is mostly supplied by (3) 12.47 kV distribution feeders. Two feeders (59F3 and 68F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town. Both a wires and a non-wires option was developed to address these projected overloads.

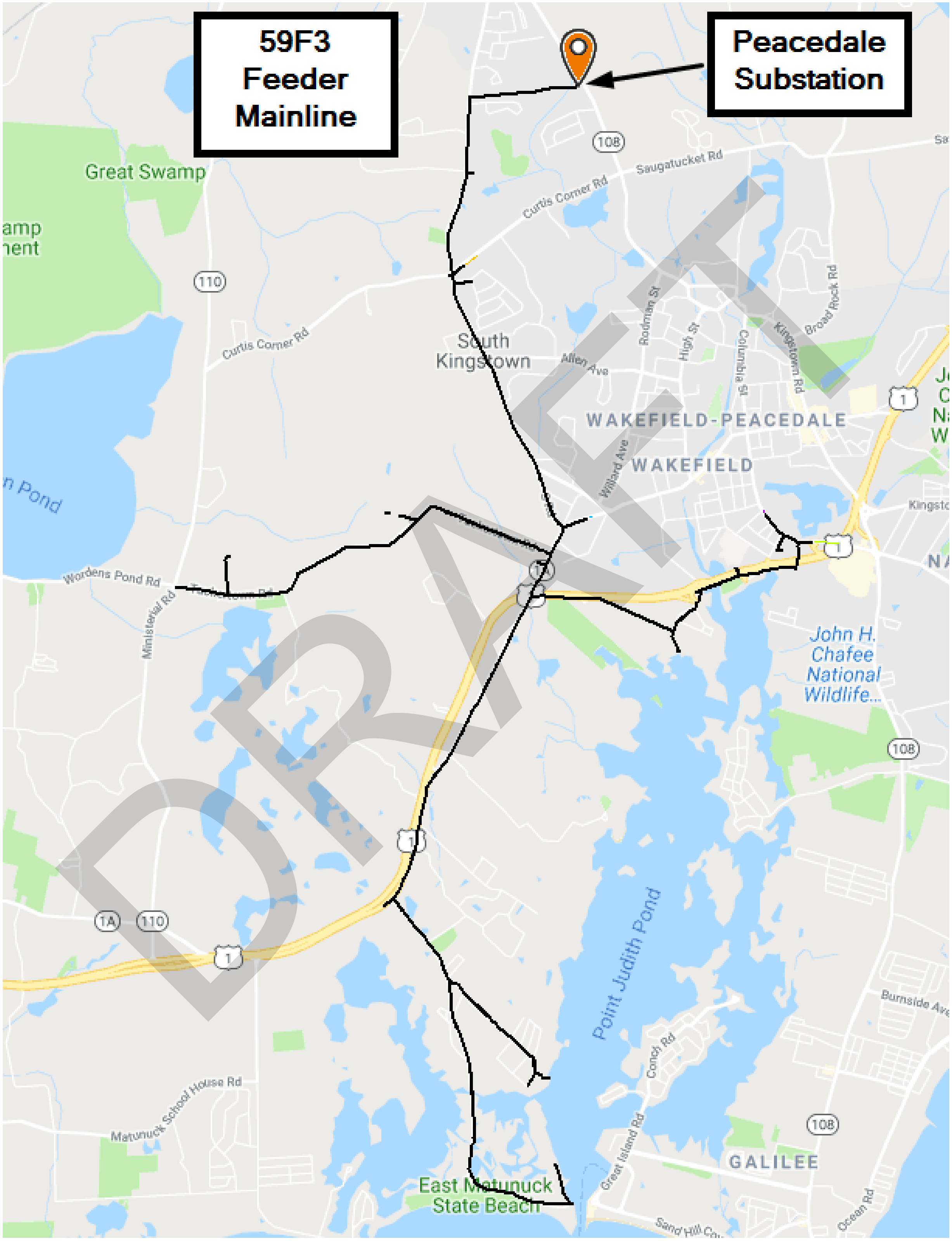
- **Wires Option**: Establish a new feeder tie between the 68F5 feeder and the 59F3 feeder. This new feeder tie provides switching flexibility to relieve both the 59F3 and the 68F2 feeders.

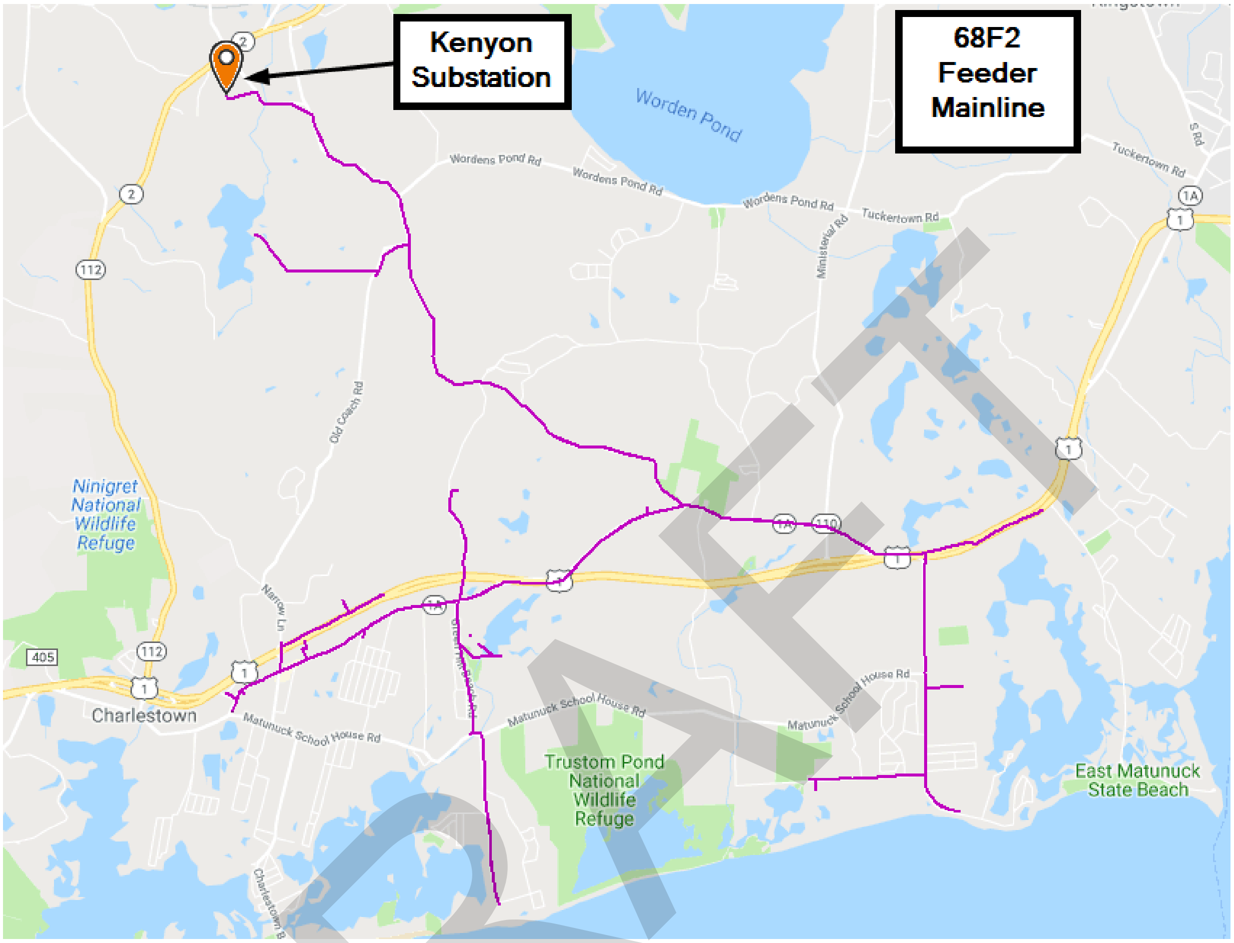
- **Non-Wires Option**: See Sections 4.1 and 4.2 below for Non-Wires requirements.

4.2. Technical Requirements

Problem Statement						
Description	The Company is seeking to provide load relief for the Peacedale 59F3 and the Kenyon 68F2 feeders.					
Technical Information	**Substation**	**Feeder**	**Operating Voltage**	**Summer Normal Rating (Amps)**	**Overloaded By**	**Load Reduction Needed (kW)**
	Peacedale	59F3	12.47 kV	492	2024	1448
	Kenyon	68F2	12.47 kV	511	2022	1646
					Total (kW)	3094

Solution Requirements	
Technical Requirements	Maintain feeder loading below 90% of summer normal rating over a ten-year period by proposing a NWA solution that reduces loading on the feeder as outlined in the Problem Statement through 2030.
In Service Date	59F3: 2024 68F2: 2022
Maximum MWHr need	Based on historic data 59F3: 13.7 MWhrs total over the course of a year by 2030. 68F2: 18.0 MWhrs total over the course of a year by 2030.
Lifetime	10 years minimum
Call Response Time	24 hours
Days of the Week needed	Any days that the day-ahead ISO-NE load forecast applied to the Project Feeders indicates that loading will exceed 90% of the Feeder Summer normal rating. This could be both weekdays and weekends.
Time of Day	Any time of day.
Number of Time Called Per Year	59F3: A minimum of 6 days based on historic data 68F2: A minimum of 5 days based on historic data In order to account for the potential of a heat wave, the project may be called for 5 or more days in a row during peak load times.
Minimum Period between Calls	24 hours


59F3
Feeder
Mainline
Peacedale
Substation
Great Swamp
Curtis Corner Rd
Saugatucket Rd
South
Kingstown
Allen Ave
Rodman St
High St
Columbia St
Kingstown Rd
Broad Rock Rd
WAKEFIELD-PEACEDALE
WAKEFIELD
Willard Ave
Wordens Pond Rd
Ministerial Rd
John H.
Chafee
National
Wildlife...
Point Judith Pond
Burnside Ave
Conch Rd
Great Island Rd
GALILEE
Ocean Rd
Matunuck School House Rd
East Matunuck
State Beach
DRAFT



Any DER location downstream of the target feeder getaways (where the feeder leaves the station) should solve the loading issue, pending a full interconnection study. See feeder maps above.

NOTE: Subject to changes in forecasted needs, solution pricing, as well as any other applicable costs and benefits, National Grid is targeting to procure NWA solutions that can supply the substation(s) load in its entirety or a large portion of it. During normal operation, for NWA technologies such as generation or storage solutions, any excess energy could be exported to the National Grid System depending on such factors as economics, portfolio fit, or others.

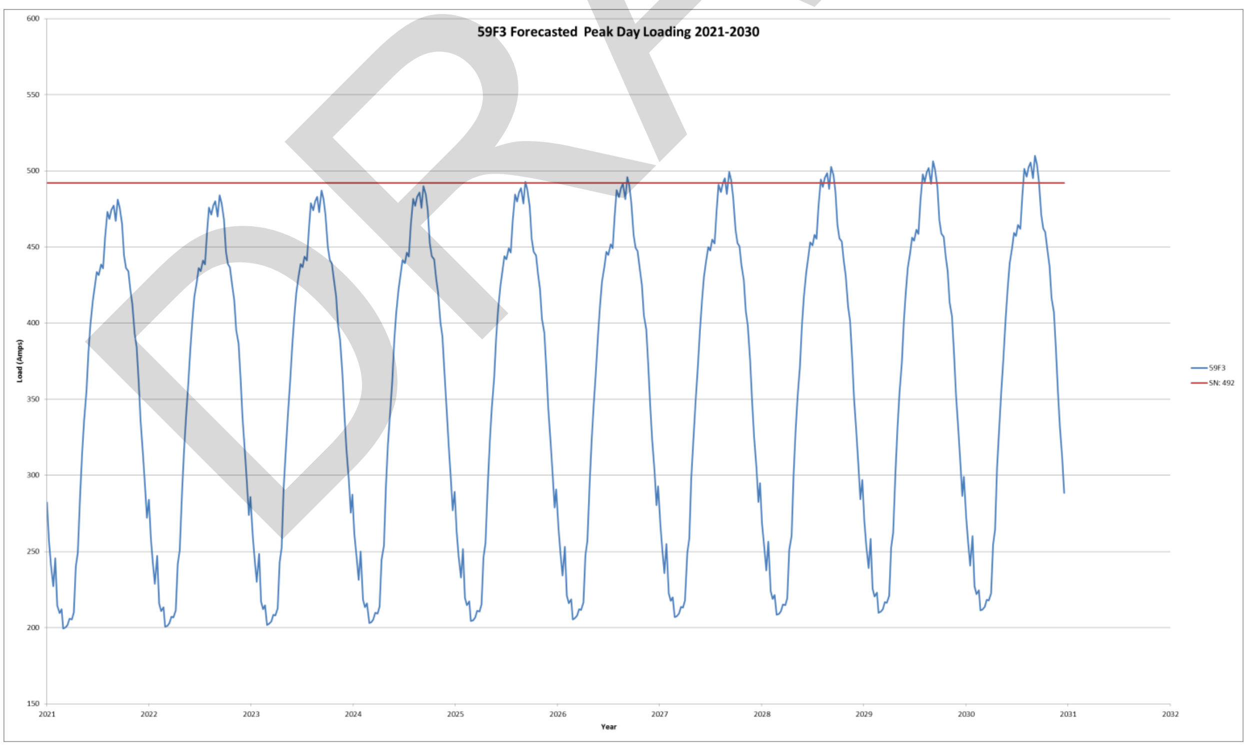
4.3. Technical Details

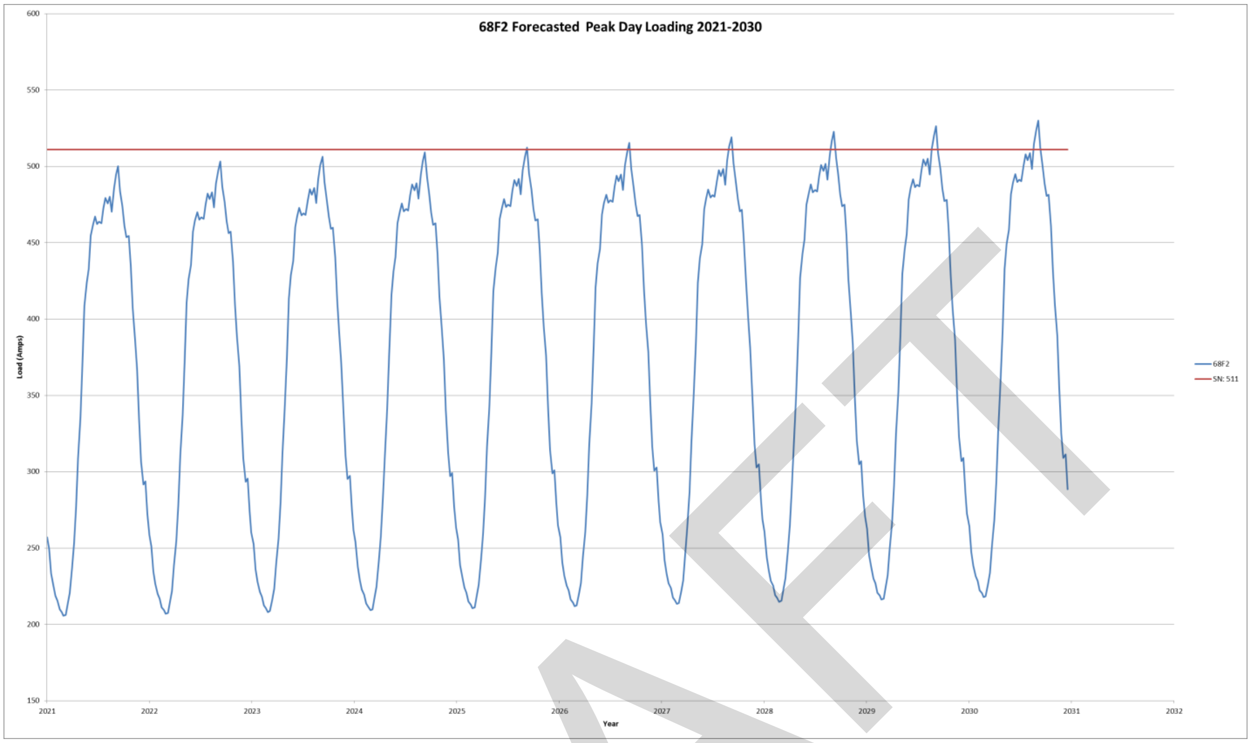
Substation	Feeder	Operating Voltage	Summer Normal Rating (Amps)	Overloaded By	Load Reduction Needed (kW)
Peacedale	59F3	12.47 kV	492	2024	1448
Kenyon	68F2	12.47 kV	511	2022	1646
				Total (kW)	3094

Substation	Feeder	Commercial Customers	Residential Customers	Total
Peacedale	59F3	73	2671	2744
Kenyon	68F2	16	4113	4129
Grand Total		89	6784	**6873**

4.3.1. Feeder Loading

Loading on the 59F3 and 68F2 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded over the next ten years. All other facilities' loadings are within their normal equipment ratings. The rating of feeders is determined by the equipment with the most limiting element (that with the lowest normal summer rating). The load forecast utilizes a technique called weather normalization, a process that assumes future year peaks will occur given high loading condition (e.g., a June peak will occur on hot day, where the temperature in the 95th percentile of hottest years). The charts below show the projected load on the feeders using the peak day at the time of study and the loads are grown according to the forecasted analysis.





4.4. Solution Timeline

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset starting in May 2022.

National Grid requires that any proposed NWA solutions will need to defer the traditional distribution asset until at least 2030. Any NWA solutions that exceed this timeline will also be considered.

5. Project Economics

National Grid is seeking solutions that provide value to the customer and are cost-effective.

The estimated net present value of deferring the wires investment for the required timeframe ("Approximate Value") is $1,328,500.

This Approximate Value is intended to be used as a total estimate associated with an NWA solution that meets the need statement described above. This Approximate Value is intended to inform developers whether their proposals are competitive; if the present value of the contract cost is near or below this value, the bid could be considered competitive. This Approximate Value is based on the current planning level estimate for the wires solution and includes all project work, capital expenditure, annual service feeds, energy service agreement payments, and the Rhode Island locational incentive value. Design of the wires solution by National Grid will continue throughout the NWA bid evaluation process, so the Approximate Value is subject to change. Please also note that the Benefit-Cost Analysis (BCA) considers numerous costs and benefits in addition to bid price and the deferral value of the traditional project.

National Grid is open to considering shared capital costs or owning a non-generation solution or asset.

National Grid encourages vendors to pursue additional relevant revenue streams to produce the most cost-effective solution.

Pricing models to be considered shall be as follows:

- Capital Expenditure
- Annual service fee
- Energy Services Agreement for capacity delivered (i.e., dollars per kW)
- Any combination of the above

6. Instructions for Bidders

6.1. Response and Deliverables

This section describes the list of items and deliverables required from the bidder. Please provide detail in your response as to why the technology/solution your firm proposes is the best-fit for this NWA project. All items should be responded to in the context of the project listed in Section 4 – Project Overview.

Please provide a concise written response under 15 pages (excluding appendices) for ease of review. There will be sections to upload additional documents on the Ariba Platform.

Responses that do not provide the requested information below can be disqualified. Bidders must submit their responses in the following format.

- Executive Summary of Proposed Technology/Solution
- Financial Plan
    - Cost of Technology/Solution for the Specified Need
    - Cost comparison to other technologies/solutions
    - Bidder's Suggested Financial Plan
- Implementation of Technology/Solution

  - Technology/Solution Reliability, with Documentation on the Solution's Technical Reliability
  - Examples of Firm's Application of Technology/Solution
- Timeline for Technology/Solution Installation
- Bidder Qualifications (To be included as an Appendix)

Bidders must additionally provide the following as an Appendix/Attachment:

- List of Historical Project Permits
- Historical Safety Record
- List of Current Environmental Certifications
- List of Historical Project Environmental/Eco awards

6.2. Evaluation Criteria

This section describes the evaluation criteria that project bid responses will be screened with.

- Cost
- Scalability
- Load Reduction Capability
- Feasibility of Proposed Technology Type/Solution
- Risk of Proposed Technology Type/Solution Creating Negative System Impacts
- Environmental or "Green" Requirement

6.3. RFP Schedule

- RFP Launch: 1/29/2019
- Bidders Conference Call: 2/13/2019
- Last date to submit questions: 3/25/2019
- Responses Due: 4/23/2019

6.4. Rhode Island System Data Portal

National Grid has developed a new web-based tool called the Rhode Island System Data Portal that houses a collection of maps to help customers, contractors, and developers identify potential project sites and with project bidding and development. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid electric service area in Rhode Island.

The Rhode Island System Data Portal can be found at the following location:

https://www.nationalgridus.com/Business-Partners/RI-System-Portal