SYSTEM RELIABILITY PROCUREMENT

2019 REPORT

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2019 SYSTEM RELIABILITY PROCUREMENT PLAN REPORT

1. Executive Summary

The purpose of System Reliability Procurement (SRP) is to identify customer-side opportunities beyond energy efficiency that are cost effective and provide the path to lower supply and delivery costs to ratepayers in Rhode Island.

This SRP Report is submitted in accordance with the Least-Cost Procurement (LCP) law, R.I. Gen. Laws § 39-1-27.7, the basis for which is the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 (as amended in May 2010),[1] and the PUC's revised "System Reliability Procurement Standards," approved by the PUC in Docket No. 4443 (SRP Standards).[2][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.*[4]

The Least-Cost Procurement law further states that SRP resources are intended to include the following:

[1]The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 (the 2006 Act) provides the statutory framework for least-cost procurement, including system reliability in the State of Rhode Island. The 2006 Act provided 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 avoiding distribution system investment, and improving overall system reliability, over time.

[2]The Least-Cost Procurement law, R.I. Gen. Laws § 39-1-27.7, requires standards and guidelines for "system reliability". On June 10, 2014, in Docket 4443, the PUC unanimously approved 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. Revisions to the Least-Cost Procurement Standards are currently under review in PUC Docket 4684.

[3] "2011 Least Cost Procurement Standards with Proposed 2014 Revisions." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 27 Mar. 2014, www.ripuc.org/eventsactions/docket/4443-EERMC-LCPS-Final_5-27-14.pdf.

[4] "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.

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

(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, Non-Wires Alternatives (NWA). Non-Wires Alternative, sometimes referred to as non-wires solution, is the inclusive term for any electrical grid investment that is intended to defer or remove the need for traditional equipment upgrades or construction, also referred to as a "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.

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 as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible*.

The Company continues its work on further coordination with other required Company filings such as the Infrastructure, Safety, and Reliability Plan (ISR Plan), the Renewable Energy Growth (RE Growth) program, and others, as discussed below. In addition, the

Company recognizes the desire to more fully implement the entire NWA and location incentive conversation with the work proposed in a particular year's ISR Plan filing. To assist with this effort, the Company will host quarterly NWA/Locational Incentive meetings to provide further transparency to the Rhode Island Division of Public Utilities and Carriers (Division) and the Rhode Island Office of Energy Resources (OER) similar to the quarterly DG meetings currently held with the Parties.

2. Introduction

The Narragansett Electric Company's d/b/a National Grid (National Grid or Company) is pleased to submit this annual 2019 System Reliability Procurement Plan Report (SRP Report) to the Rhode Island Public Utilities Commission (PUC). The SRP Report has been developed by National Grid via iterative process with the Energy Efficiency Collaborative (the Collaborative).[5][6]

This Plan is being jointly submitted as a Stipulation and Settlement (Settlement) between the Division, the Energy Efficiency and Resource Management Council (EERMC), Acadia Center, Green Energy Consumers Alliance[7], TEC-RI, the OER, and National Grid (together, the Parties), and addresses a range of topics discussed by members of the Collaborative regarding the Company's SRP Report for calendar year 2019.

The Company is working to bring the SRP Report in line with the other state filings the Company submits, to ensure cohesive and comprehensive plan framework and implementation. The Company has coordinated with the Energy Efficiency (EE) Plan to ensure that efforts are not being duplicated.

Section 2.1(D) of the SRP Standards requires that the Company identify transmission and distribution (T&D) projects that meet certain screening criteria for potential NWA solutions that reduce, avoid, or defer traditional T&D wires solutions. NWAs are targeted actions by customers or the utility that promote the deferral of a specific Company investment in transmission or distribution infrastructure. Section 2.1(I) of the SRP Standards further require the Company to submit, by November 1 of each year, an 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 behind NWA analysis, please see Section 6.

[5] Members of the Collaborative presently include the Company, the Rhode Island Division of Public Utilities and Carries (Division), the Rhode Island Office of Energy Resources (OER), TEC-RI, Green Energy Consumers Alliance, Acadia Center, along with participation from several EERMC members, and representatives from the EERMC's Consulting Team.

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

[7] Formerly People's Power & Light.

National Grid seeks approval of this 2019 SRP Report in accordance with the guidelines set forth in Section 2.1 of the SRP Standards.

3. Summary of the Company's Proposal

This 2019 SRP Report includes the following sections: a new section detailing how the SRP Report aligns with the Power Sector Transformation initiative; a new section detailing how the SRP Report aligns with Docket 4600; a review of the infrastructure projects studied for NWA potential; a discussion of the work the Company has been doing to create the Rhode Island System Data Portal (Portal) and associated marketing and engagement plan; updates on the Tiverton NWA Pilot (Tiverton Pilot) for load curtailment in Tiverton and Little Compton; status updates on the Little Compton Battery Storage Project (LCBS Project); a discussion of the South County East NWA (SCE NWA) opportunities; a new proposal for a Customer-Facing Program Enhancement Study (Enhancement Study); an analysis of locational incentives for solution providers in Rhode Island; and a discussion of the current and prior year incentive items of the SRP Incentive Mechanism.

Section 4 discusses the SRP Report's coordination with Power Sector Transformation and how SRP addresses the goals of Power Sector Transformation. The SRP is an effort to control the long-term costs of the electric system, give customers more energy choices and information, and build a flexible grid to integrate more clean energy generation through NWA opportunities and applied technologies, initiation of the Rhode Island System Data Portal, and engagement with third-party solution providers.

Section 5 details how SRP aligns with and advances Docket 4600 principles and goals. SRP advances Docket 4600 goals via successful NWA projects and application of NWA technologies, adherence to Least-Cost Procurement law, enabling third-party solution providers through locational incentives, and implementation of the Rhode Island Test (RI Test).

Section 6 further discusses how the Rhode Island System Data Portal, an interactive web-based tool, provides information to stakeholders, customers, and third parties regarding the status of the Company's distribution grid. The Company is providing an update on the development and rollout of the Portal and an update on the associated customer engagement and marketing campaign plan for the Portal. The marketing campaign is part of an effort to promote the Portal to potential distributed energy resource (DER) solution providers and to increase industry knowledge of the Portal and incentives available through existing Company and state programs for conservation, peak load relief, and renewable energy projects in highly-utilized areas. The Company intends to continue the marketing campaign effort for the Portal through the 2019 calendar year.

Section 7 was previously a subsection under the Tiverton NWA Pilot in the 2018 SRP Report[8] and only addressed the Tiverton area for forecasted load growth. However, Forecasted Load Growth for NWA Opportunities has now been made a main section to holistically address areas of need on the Rhode Island electric distribution grid, especially with regard to where NWA opportunities may populate.

In Section 8, the Company provides an update on the final evaluation of the Tiverton NWA Pilot and its scheduled conclusion, which the Company proposed in the 2012 System Reliability Procurement Report. The 2018 SRP Report recognized that the Tiverton NWA Pilot, while still effectively achieving the overall goal of deferring the Tiverton substation upgrade, has been underperforming on its quantitative curtailment goal.

Section 9 details the status and technical details of the LCBS Project as one of the four current NWA proposals, and is being re-proposed from the 2018 SRP Report for continuation in this 2019 SRP Report. The LCBS Project includes a battery storage system that has been proposed to be installed in Tiverton, Rhode Island to address peak load relief need in the areas of Tiverton and Little Compton. Although the LCBS Project is located in the same footprint as the Tiverton Pilot and is intended to further defer the $2.9 million substation upgrade detailed in the Tiverton Pilot proposal in Docket 4296, the LCBS Project is a separate effort from the Tiverton Pilot. At this time, negotiations are still on-going with the developer who initially proposed the LCBS. Depending on the outcome of these discussions, the Company may need to re-issue this RFP to see if other developer or technology options are available to provide the proposed load relief levels.

Section 10 discusses the SCE NWA opportunities. These are NWA proposals in this 2019 SRP Report, and are new proposals. This section provides information from the South County East Area Study which details the potential for NWA opportunities in the Towns of Exeter, Narragansett, and South Kingstown. The Company proposes for the 2019 calendar year to identify NWA solutions for each of the South County East areas through the RFP bid process.

Section 11 proposes a new program, the Customer-Facing Program Enhancement Study. The Enhancement Study will gather lessons learned and relevant research to use in the development and testing of novel customer engagement approaches. These approaches will be designed to increase enrollment, participation, and retention in customer programs that can be used for demand response. The Company will issue a bid for solicitation to

[8] "2018 System Reliability Procurement Report." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Co. d/b/a National Grid, 1 Nov. 2017, www.ripuc.org/eventsactions/docket/4756-NGrid-SRP2018_11-1-17.pdf.

conduct the Enhancement Study in three phases. Phase 1 of the Enhancement Study will be conducted in 2019.

Section 12 entails a discussion of Rhode Island Locational Incentives, regarding the locational incentive research and analysis conducted in 2017, the current status of distributed generation (DG) growth and of electric peak load in Rhode Island, and the proposal and the future for locational incentives in Rhode Island.

Section 13 proposes new, progressive action-based incentives to further advance achievement of LCP goals. The Company proposed, and was subsequently approved, to earn possible incentives from last year's SRP plan. Please see Section 13 for the incentives proposed for the 2019 calendar year and for the earned incentives to date from the 2018 SRP Report. The Company will request earnings on the 2018 SRP Report incentive actions in the 2020 SRP Report, since the full 2018 calendar year will be complete and assessed by the time of the 2020 SRP Report.

Section 14 is the funding request for this Plan. The Company estimates that approximately $439,300 in incremental costs will be required in 2019 to implement the projects and initiatives detailed in this Report. The Company is requesting recovery for these funds and a four-year commitment to the LCBS Project funding, subject to additional budget funding requests to be made in the 2020, 2021, and 2022 SRP Reports.

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

4. Coordination with Power Sector Transformation

The Power Sector Transformation (PST) Phase One Report[9] 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 at lower costs to customers. Such NWA opportunities may include technologies and methodologies such as demand response, solar, energy storage, combined heat and power (CHP), microgrid, conservation or energy efficiency measure, and other distributed energy resources (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

[9] "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.

meet the greenhouse gas emission reduction goals specified in the Resilient Rhode Island Act of 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.

5. Advancing Docket 4600 Principles and Goals

The Docket 4600-A Guidance Document directed 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."[10]

Along with the quantitative benefits detailed in the Plan, as measured by the RI Test, the System Reliability Procurement Plan for 2019 advances Docket 4600 principles and goals.[11]

To meet this directive, the Company describes in the table below how the Plan 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.

[10] Approved final clean version of Guidance Document 10/27/17.
[11] PUC Report and Order No. 22851 accepting the Stakeholder Report. Written Order issued July 31, 2017.

Table 1: 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.	Advances: 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.	Advances: The SRP Report strengthens the economy by engaging economic benefits of the RI Test model in the planning of NWA opportunities. 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: 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.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits.	Advances: The SRP Report promotes investment in NWAs, which include such technologies as battery storage, demand response, and distributed generation. The LCBS Project and the closing down of the Tiverton NWA Pilot are examples of this.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.	Advances: 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 least-cost procurement law, and therefore compensates DERs in a cost-effective manner.

4600 Goals for Electric System	Advances/Detracts/Neutral
Appropriately charge customers for the cost they impose on the grid.	Advances: The proposed Locational Incentives section begins the conversation for appropriate compensation or charges for that cost that customer side resources impose on the grid.
Appropriately compensate the distribution utility for the services it provides.	Advances: 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: The SRP Report aligns Company, customer, and policy objectives and interests by implementing the SRP Incentive Mechanism, to enable actualization of NWA projects and SRP resources that benefit both the distribution grid and Rhode Island customers. Additionally, the Company implements prudent and effective cost recovery via the NWA projects proposed in the SRP Report. Furthermore, SRP follows Least-Cost Procurement law, the basis for which is the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 (as amended in May 2010).

6. Consideration of NWAs in System Planning

All transmission and distribution needs continue to be screened for NWA feasibility. To determine whether an NWA solution is feasible, the Company screens traditional solution transmission and distribution projects against the criteria listed in Section 2.1(D) of the SRP Standards, which are aligned with the Company's internal planning document. The Company determines NWA suitability during the following processes:

- First, and most important, is the NWA screening and analysis that is included within comprehensive distribution planning studies.

- Second, when other asset management and planning projects are initiated.

NWA screens are applied against an identified issue, opportunities are investigated to adjust one or more of the screening criteria, and partial NWA opportunities are investigated.

If the Company determines that an NWA solution is feasible, the NWA solution is fully developed and then proposed through the next SRP Report. If a wires solution is the best option, then that traditional solution project is fully developed and incorporated into the Company's Electric Infrastructure, Safety and Reliability Plan (ISR Plan)[12].

There were 48 discretionary distribution projects initiated between April 1, 2017 and March 31, 2018, and all 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 is also continuing to progress its NWA consideration in its distribution area studies, including the South County East (SCE) Area Study. The Company identified three NWA opportunities in the SCE study, in the towns of Narragansett, South Kingstown, and Exeter. The Company is actively pursuing Requests for Proposals (RFPs) with solution providers to test the market for NWA solutions in these areas as approved in the Company's 2018 SRP Report.

[12] Notably, newly initiated projects comprise only part of the budgets and assets that are included in the Company's Electric ISR Plan, which includes all projects that will be part of the Company's capital investment portfolio in a given year, which typically includes multi-year projects that may already be in progress. Also, projects that ultimately do not pass NWA screening in a given year may not always be included in the ISR Plan budget for that year due to a variety of constraints. Instead, these projects will be proposed as the ISR Plan budgets allow in future years. Therefore, it is possible that there may be projects and budgets related to load growth in the ISR Plan that are not included in the screening conducted for this Report. Once a solution is chosen for either a transmission or distribution project and is included in an annual ISR Plan filing, it is not screened for NWA feasibility again.

Table 2: South County East Study - NWA Analysis

Area	Load Relief	Traditional Wires Option	Traditional Wires Option
Narragansett	2.7 MW	Feeder upgrade/reconfiguration	$2.50M
South Kingstown	2.0 MW	Feeder upgrade/reconfiguration	$1.25M
Exeter	0.7 MW	Feeder upgrade	$1.50M
Total	**5.4 MW**		**$5.25M**

Additionally, the Company has some NWA opportunities that were identified in past Area Studies that are pending re-evaluation. 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.

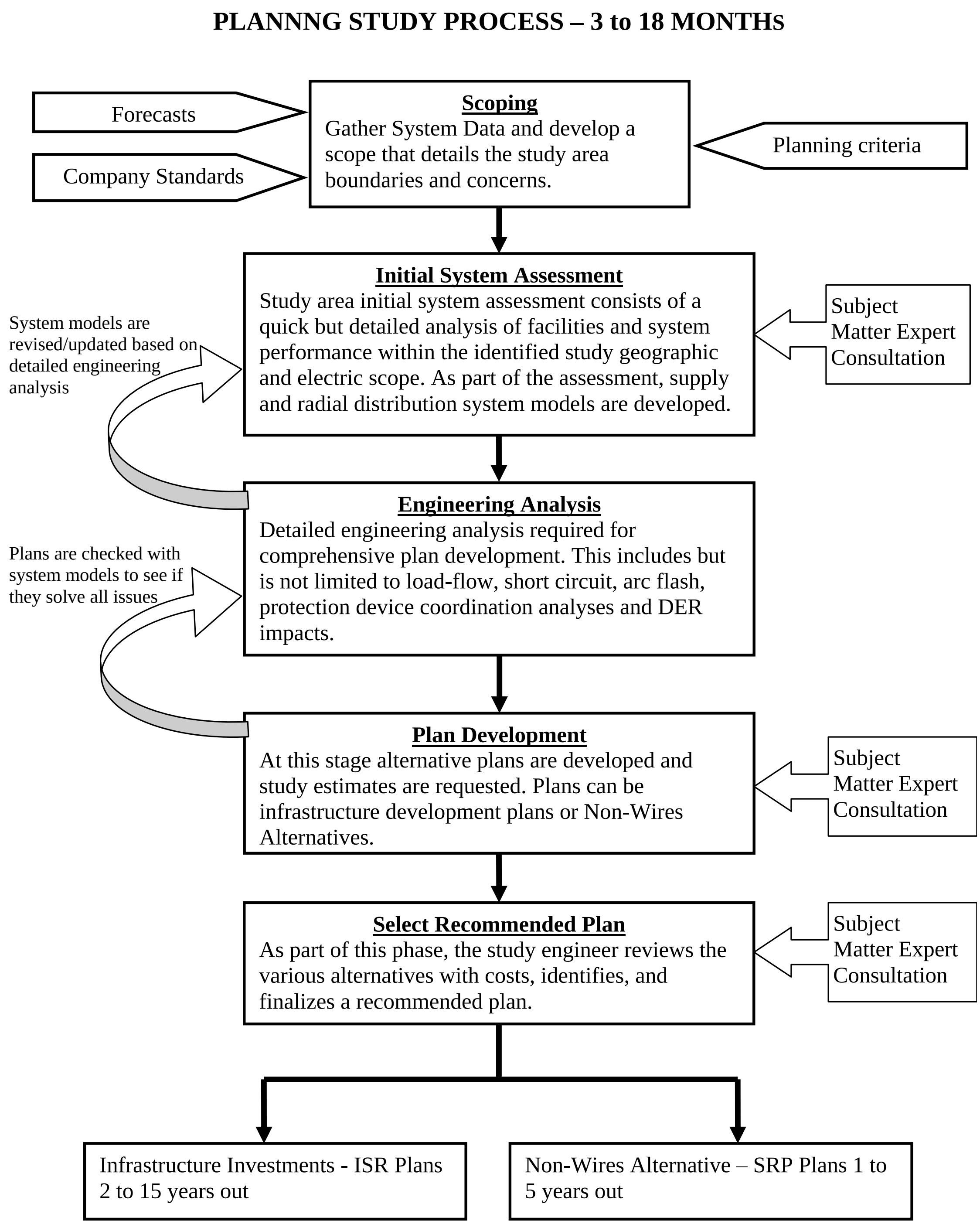
Table 3: NWA Areas to be Re-Evaluated

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

The Company shall also issue, by December 31, 2019, at least two new Requests for Proposals (RFPs) from third-party developers for the purchase of a set of NWA resources. The decision on where to locate the NWAs will be based on the information provided in the Portal, as well as on distribution area studies. The maximum amount payable for NWA resources will be either annualized amount of the revenue requirement of the traditional utility wires option or the location-based avoided costs (when such costs are determined and accepted). Any contracts to procure NWAs would have to be approved by the Rhode Island PUC as required for all non-tariff contracts.

For reference on timing of the NWA review process and possible inclusion in a specific year's ISR Plan, the figure on the following page is a Distribution Planning Study Process flowchart which outlines the major steps and study-based inputs in the overall area study process. 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



6.1 Rhode Island System Data Portal

This section provides an update for this RI SRP 2019 Plan regarding the Rhode Island System Data Portal and associated resources.

The 2018 SRP Report include a proposal for the initial work on the Rhode Island System Data Portal. Future work and costs related to the Portal is included in the current rate case under Docket 4770. The initial version of the Portal went live on June 30, 2018. A public landing page for the Portal is located on the customer-facing National Grid website[13].

The Portal includes the following:

1. Company Reports
    a. Distribution Planning Study Process
    b. Distribution Planning Criteria
    c. 2018 Electric Peak (MW) Forecast
    d. Electric Infrastructure, Safety and Reliability (ISR) FY 2019 Proposal
    e. 2018 System Reliability Procurement (SRP) Report

2. Distribution Assets Overview
    a. Specific Distribution Feeder and Substation Information (Feeder ID, operating voltage, etc.)
    b. Summer Normal Rating
    c. 2017 Recorded Loading, and Forecasted Loading to 2027

3. Heat Map
    a. An interactive color-coded map of Distribution Feeders based on 2018 forecasted load compared to Summer Normal Rating
    b. Provides information on circuits that would benefit from DER interconnection for load relief, and on circuits that have existing capacity for Electric Vehicle (EV) charging stations, heat pumps, and other beneficial electrification opportunities.

4. Hosting Capacity
    a. The Hosting Capacity Map is currently under development with a planned go-live date of September 30th, 2018
    b. Substation ground fault overvoltage protection (3V0) status; installed or not, if 3V0 is in construction or slated for construction, and the proposed

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

in-service date. 3V0 installation makes a substation transformer “DG ready”.

c. Distribution Generation (DG) interconnected and in-process DG projects

The Company is continuing to finalize the Hosting Capacity interactive map for the Data Portal. This requires additional modeling and analysis for color coding of feeders based on maximum Hosting Capacity.

Additionally, further enhancement of the Portal is proposed to account for optimal level 3 EV charging locations (units that are approximately 300 kW each).

This additional enhancement of the Portal will be completed by July 1, 2019.

The Portal will have highlighted areas of loading (red will represent high load, green will represent low load); however, this effort will identify locations at or near large public and private fleet parking areas.

6.2 Market Engagement with NWAs

To nurture these 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 proposes to continue to develop and deploy a Marketing and Engagement Plan in 2019. The Marketing and Engagement Plan will build on the results of the 2018 plan.

The proposed Marketing and Engagement Plan would promote the Portal described in the previous section, and promote incentives already available through existing Company and State programs (e.g. net metering, RE Growth program, and the ConnectedSolutions Demand Response program).

Please see Appendix 8 for the current iteration of the 2018 Market and Engagement Plan.

By March 31, 2019, the Company will develop and circulate to the Parties the 2019 Marketing and Engagement Plan with proposed tracking mechanisms to capture its effectiveness. The 2019 Marketing and Engagement Plan is a continuation of the already live 2018 Marketing and Engagement Plan and remains flexible to support the new projects proposed in 2019.

6.2.1 Market Engagement Activities to Date

To date, the Company has launched Educational Webinars for developers in Rhode Island, utilizing email marketing and online registration for those webinars and leveraging available promotional opportunities through the RI Solar Stakeholders mailing list, via outreach to the RI OER, and through in-person meetings.

A customer-facing page was developed on the National Grid website to serve as a front door to the Portal and to make it easier for developers to find. 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 kicked off in September and the first 30-day report will be circulated in early October 2018.

The first quarterly report of results for July to September will be compiled and circulated in October 2018 and will include webinar, digital advertising metrics.

Additionally, the Company has showcased the Portal at a company event called The Rhode Island Customer Listening Forum in August 2018 where the Portal was demonstrated to customers and developers by company representatives.

Please see Appendix 9 for the 2018 Market and Engagement Plan Year-to-Date Results, which contains the results and metrics from market engagement activities for the current year so far.

6.2.2 Market Engagement Funding Plan

The Company proposes a budget of $124,800 to support this initiative in 2019. This request is similar to the funding request in the 2018 SRP Report. The Company estimates $80,000 will be needed to support the creation and dissemination of marketing materials and tracking mechanisms. The Company estimates that $44,800 will be needed 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.

7. Forecasted Load Growth for NWA Opportunities

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

The Company's distribution system serves close to 500,000 electric 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 1.

7.1 Forecasted Load Growth in the Tiverton Area

The Tiverton and Little Compton annual weather-adjusted summer peaks are expected to increase at average annual growth rates of 0.3% and 0.1% respectively for the next 10 years. These rates are greater than the statewide average annual growth of -0.2%.

7.2 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 0.5% for the next 10 years. This rate is greater than the statewide average annual growth rate of -0.2%.

8. Tiverton NWA Pilot

The Tiverton NWA Pilot was a demand response pilot program implemented to address the electrical distribution grid need of the Tiverton substation, which served customers in the Towns of Tiverton and Little Compton.

In accordance with the scheduled plan and as proposed in the 2018 SRP Report, the Tiverton NWA Pilot ended on December 31, 2017.

The 2018 SRP Report recognized that the Tiverton NWA Pilot, while still effectively achieving the overall goal of deferring the Tiverton substation upgrade, has been underperforming on its quantitative curtailment goal.

The following sections include updates on the Tiverton Pilot since the 2018 SRP Report was filed in Docket 4756. This information is included in this SRP Report, consistent with the reporting in past SRP Reports to help clarify the reasons the Company is not proposing to extend the Tiverton Pilot beyond 2017.

8.1 Implementation

The following sections provide details on the implementation of the Tiverton Pilot's most recently completed year of activities and a progress report on the current year's activities to date. For more information regarding the implementation activities in previous years, please see past SRP Reports.

8.1.1 2017 Summary

The 2018 SRP Report contains the majority of the 2017 calendar year progress and results. This 2019 SRP Report provides end-of-the-year updates to the relevant components of the Tiverton Pilot.

The updated table below shows that outreach to Tiverton Pilot customers in 2017 produced 224 pre-qualified leads for the enhanced DemandLink incentives compared with 428 leads for the same period in 2016, and 730 leads in 2015.

Table 4: Penetration of Interested Tiverton Pilot Leads 2018

Pilot Year (through month)	Leads Generated	Customer Penetration*
2012 (December)	209	4.2%
2013 (December)	1061	21.3%
2014 (December)	655	13.2%
2015 (December)	730	14.7%
2016 (December)	428	8.6%
2017 (December)	224	4.5%
Total through December 31, 2017	**3,302**	**66.5%**

**** Based on total of 4970 available Tiverton Pilot customer phone numbers***

The number of qualified leads for measures other than the EnergyWise home energy assessments was much lower than in previous years during the same time period. The Company believes that this is due in part to the fact that the Tiverton Pilot reaches a saturation point with customers who respond to telemarketing.

To close out the remainder of 2017, the Company made another active push to engage as many eligible customers as possible to participate. This push included a second telemarketing pass, direct mail, social media, and email marketing.

No additional demand response events were called following filing of the 2018 System Reliability Procurement Report.

Regarding participation and kW savings metrics, please refer to the National Grid Rhode Island System Reliability Procurement Pilot: 2012-2017 Summary Report in Appendix 3.

In accordance with the scheduled plan and as proposed in the 2018 SRP Report, the Tiverton NWA Pilot ended on December 31, 2017.

8.1.2 Final Closeout of Pilot

With the conclusion of the Tiverton Pilot at the end of the 2017 calendar year, the only remaining activities for the 2018 calendar year are the final evaluation and the final notification to customers.

The final notification to customers of the Tiverton Pilot's completion occurred on June 5, 2018 via email. The email notification was sent to all customers participating in the Tiverton Pilot that had email addresses still subscribed for the Company's notifications. All customers participating in the DemandLink demand response program of the Tiverton Pilot have been automatically enrolled in the ConnectedSolutions program to allow them to continue participating in demand response events. Email services and metrics were provided by Questline.

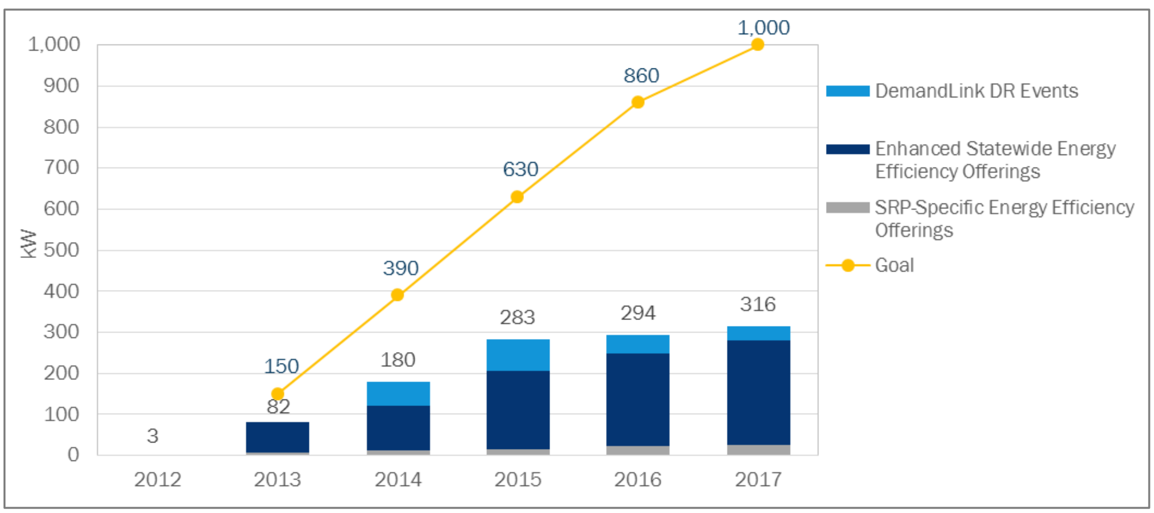
The final evaluation of the Tiverton Pilot is described in the Evaluation section that follows.

8.2 Evaluation

A final evaluation of DemandLink, the brand name for National Grid's load curtailment program of the Tiverton Pilot, in Tiverton and Little Compton was completed in July 2018 by Opinion Dynamics Corporation (ODC). The final evaluation report is included in Appendix 3. The final evaluation examined the effectiveness of each of the strategies employed by the Company to deliver 1 MW of load relief by 2017 (the last year of the Tiverton Pilot) to defer the new substation feeder for 4 years, from 2014 to 2018. These strategies included (1) implementation of the DemandLink Programmable Controllable Thermostat Program, (2) enhancement of existing statewide energy efficiency offerings, and (3) introduction of new SRP-specific energy efficiency offerings.

The final impact evaluation found that the Tiverton Pilot fell short of its 1 MW load reduction goal. However, the Tiverton Pilot's initial progress postponed the investment of the wires alternative that would have occurred in 2014, if not earlier. The investment in the substation upgrade was further deferred due to slower than expected load growth and cooler summer temperatures in 2017.

Figure 2: Cumulative Load Impacts (kW) Compared to Goal



The evaluation found that the EnergyWise and Small Business Direct Install programs were the largest contributors to total load impacts, with 152 kW (48% of the total) and 96 kW (31% of the total), respectively. Demand response events accounted for 36 kW (11% of the total).

Note that the 316 kW of cumulative load impacts in 2017 differs from the value of 735 kW reported in Table S-7 of Appendix 2. This is because Table S-7 is intended to present the theoretical DR capacity of the thermostats installed based on an assumed per-unit savings and level of participation. Conversely, the numbers ODC calculated are based on actual events. Actual pilot participation in DR events varies greatly in a relatively small population size depending on the weather and individual customer needs. Therefore, the Company presented the amount of theoretical savings installed as the benchmark for determining if the quantitative installation goal of 1MW was achieved.

8.2.1 Key Findings and Recommendations

The final evaluation provided the following key findings and recommendation for any future program offerings.

1. Demand Response

   The Tiverton Pilot resulted in lower than expected savings from residential demand response events. The evaluation found three main contributing factors to this outcome: (1) low enrollment in the program; (2) significant connectivity issues, especially for participants with window AC; and (3) an event strategy that resulted in lower-than-expected hourly-per-household event savings.

Table 5: Summary of Demand Response Impacts

Program Year	# of Events	Per-Thermostat Impact		Mean # of Thermostats in Analysis[b]	Program Impact (kW)
		Runtime Reduction	kW[a]		
Central AC					
2014	3	8.6%	0.32	176	56
2015	15	13.3%	0.49	155	76
2016	18	10.9%	0.40	115	46
2017	15	14.8%	0.52	68	36
Window AC					
2014	3	n/a	0.07	28	2.0
2015	15	n/a	0.04	14	0.6
2016	15	n/a	0.045[c]	0.4	0.018
2017	n/a				

The evaluation also provided several recommendations for the Company to consider in future demand response programs:

- Future programs should not rely on equipment that requires customer action or reinstallation each year. The window AC plug devices used in the Tiverton Pilot were discontinued in 2016 due to significant connectivity issues and misuse by customers.

- Deploy the following changes to the demand response strategy to increase the savings per thermostat:
    - Deploy a more aggressive offset strategy for events (ex. 3°F or 4°F set point) or consider cycling of the unit instead.
    - Maintain the event length at 3 hours to avoid negative savings in the last hour of the event.
    - Consider precooling before event.
    - Only call events when peak demand is predicted.

- Conduct additional testing of central AC thermostats to confirm connectivity before events begin.

2. Enhancement of existing statewide energy efficiency offerings

   National Grid's enhancement of existing statewide offerings was the most successful component of the Tiverton Pilot, contributing 255 kW, or 81%, to total Tiverton Pilot load impacts. There were two main limitations to this strategy reaching 100% of its goal. First, lighting measures accounted for the clear majority of the savings in the EnergyWise Program. While these measures contributed significantly to the savings in the early years of the Tiverton Pilot, the changing baseline for residential lighting measures (due to EISA standards and resulting market transformation) resulted in decreased claimable savings from these measures over time. The second barrier was the determination that it was too costly to obtain the needed participation in the small business sector that caused the Tiverton Pilot to capture the full potential for savings from this population of customers.

   The evaluation recommends that targeted energy efficiency continue to be utilized in future initiatives. However, the Company should diversify away from lighting measures and consider new outreach channels to reach small commercial customers.

3. Tiverton Pilot-specific energy efficiency offerings

   The Company deployed two Tiverton Pilot-specific energy efficiency offerings – rebates for new energy efficiency window AC units and window AC recycling. Overall, these new rebates generated 25.2 kW in peak load reductions (8% of Tiverton Pilot totals). The majority of these impacts came from recycling inefficient window AC units and not replacing them with a new unit. The evaluation determined that the largest barrier to this strategy's success was lack of customer awareness. Only 38% of eligible customers were aware of these offerings.

The evaluation determined there are still significant savings opportunities for these measures in the Tiverton Pilot area. Approximately 4 out of 10 customers in the Tiverton Pilot area indicated they used or planned to use window AC to cool their home in the summer. In addition, 19% of customers had window AC units that they no longer used or that they were thinking about replacing in 2017. In order to reach these customers, the evaluation recommends that any future efforts should deploy more focused outreach on these two measures and consider offering time-limited enhanced rebates to increase participation.

With the end of the Tiverton Pilot and the planned battery storage project, it no longer makes sense to deploy the window AC rebate and recycling measures as a deferral strategy. However, the recommendations and results of the evaluation for these measures will be considered by the Energy Efficiency strategy team for any future offerings to coastal communities, as well as to other future initiatives.

The Company plans to apply the results of this evaluation and the lessons learned over the course of the Tiverton Pilot to future initiatives. Although the Tiverton Pilot did not meet its 1 MW reduction goal, the Company gained valuable insight into customer behavior, marketing effectiveness, and demand response strategies that will help improve customer offerings in the future.

8.3 Benefit-Cost Analysis

The benefit-cost calculations for this Tiverton Pilot have been completed using the Total Resource Cost test.[14] Figures for Tiverton Pilot years 2012 through 2018 have been updated to reflect actual results, year-end projections and data from the EE impact evaluation, as applicable.

[14]For a detailed description of the cost and benefits associated with the cost-effectiveness framework, see 2012 SRP Report - Supplement, February 1, 2012, Docket 4296.

Table S-2: Summary of Cost-Effectiveness for Tiverton NWA Pilot

Table S-2
System Reliability Procurement - Tiverton/Little Compton
Summary of Cost-Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	2018	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$568.0**	**$0.0**	**$5,074.6**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$66.94	$0.0	$3,348.7
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$341.6	$0.0	$1,043.7
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$0.0	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$510.9**	**$90.8**	**$3,617.4**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$281.3	$0.0	$1,664.1
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$229.6	$90.8	$1,953.3
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**1.11**	**-**	**1.40**

Notes:
(1) Focused EE benefits in each year include the NPV (over the life of those measures) of all TRC benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.
(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.
(3) DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.
(4) Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.
(5) EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install programs. These are the programs through which measures in this SRP pilot will be offered.
(6) SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.
(7) All costs and benefits are in $current year except for deferral benefits.
(8) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers reflect year end projections.

The Tiverton Pilot remains cost-effective over its life, with a benefit/cost ratio of 1.40 as shown in Table S-2 above. Each year is also cost-effective on its own, aside from 2018 which has been previously designated for final post-Pilot evaluation.

For comparison with the RI Test, please refer to Appendix 10. Table S-2 and Table S-5, regarding the summaries of cost-effectiveness and of incremental benefits respectively, have been recalculated using the RI Test model and benefits. These revised tables, Table RIT-S-2 and Table RIT-S-5 in Appendix 10, illustrate some quantitative differences between the TRC and RI Tests. Note that both benefit and cost values have changed, with the cost values in Table RIT-S-2 changing according to the revised applicable cost measures. The current 2019 RI Test model and associated benefits and factors were used for this comparison.

Table RIT-S-2 details a lower, yet still cost-effective, overall Benefit-Cost Ratio (BCR) of 1.06, compared to the overall BCR of 1.40 from Table S-2.

There are only costs for the Tiverton Pilot in 2018 because these costs account for the final post-Pilot evaluation. No other costs have been incurred because the Tiverton Pilot ended on December 31, 2017 as planned.

All costs and benefits in this analysis are in current year dollars, meaning that the avoided costs are inflated for each year. The savings associated with this Tiverton Pilot are categorized in the same way as the benefits. These savings are shown in Table S-4 of Appendix 2. As projected, the Tiverton Pilot has created over $5 million in benefits in the Tiverton/Little Compton area over its six-year lifetime. For each $1 invested, this Tiverton Pilot created $1.40 of economic benefits over the lifetime of the six-year investment.

8.4 Coordination with SRP Solar DG Pilot

Between 2015 and 2017, the Office of Energy Resources (OER), in coordination with National Grid, conducted a pilot program to understand the feasibility and practicality of using solar PV distributed generation (DG) to reduce peak load in the towns of Tiverton and Little Compton sufficiently to defer system upgrades (referred to as the Solar DG Pilot). Through a targeted Solarize campaign in Spring 2015 and other outreach, 57 residential and 1 commercial-scale customer installed 649 kW of aggregate solar capacity. Importantly, the Solar DG Pilot used incentives to encourage participants to install westward-facing solar systems to better align the timing of PV output with peak demand.

The Solar DG Pilot was evaluated in its entirety by an independent evaluation in 2018, which included an impact evaluation of aligning DG with peak demand and a process evaluation of program delivery and customer perspectives. The Solar DG Pilot evaluation report[15] may be found on the OER website[16]. Evaluators found that the incentive structure, while confusing, did promote adoption of westward-facing solar systems, which increased peak PV output. However, maximum electric system peak demand occurred later in the day than peak PV output, limiting the effectiveness of solar DG in reducing peak loads on the feeders. Ultimately, the installed capacity through the Solar DG Pilot did not achieve the 250-kW peak load reduction target. Lessons learned from the Solar DG Pilot will inform future consideration of solar DG as a mechanism for reducing peak load as well as program delivery, implementation, and incentive structure for solar DG as a component of future NWA projects.

[15] Shaw, Shawn, et al. *System Reliability Procurement Distributed Generation Pilot Evaluation Report*. Rhode Island Office of Energy Resources, 2018, *System Reliability Procurement Distributed Generation Pilot Evaluation Report*, www.energy.ri.gov/documents/SRP/2018-srp-dg-pilot-emv-final-report.pdf.

[16] "The OER System Reliability Procurement Solar DG Pilot Project." *State of Rhode Island: Office of Energy Resources*, Rhode Island Office of Energy Resources, 2018, www.energy.ri.gov/electric-gas/future-grid/oer-system-reliability-solar.php.

9. Little Compton Battery Storage Project

9.1 Project Proposal

For 2019, the Company proposes to continue the Little Compton Battery Storage Project (LCBS Project)[17], which will include a battery storage system to be installed in Tiverton, RI to provide peak load relief. The storage system will be capable of providing 250 kW of continuous peak load relief in the areas of Tiverton and Little Compton between the hours of 3:30pm and 7:30pm during the months of June through September.

The LCBS Project was previously proposed in the 2018 SRP Report, and is being re-proposed in this 2019 SRP Report as explained in this section.

The LCBS Project would provide load relief in the same geographical footprint as, and is the successor NWA project to, the Tiverton NWA Pilot. An RFP solicitation for an integrated NWA solution was previously approved within the 2017 SRP Report in Docket 4655 as part of the Tiverton Pilot. The Company completed the RFP in early 2017, resulting in a battery storage project as the winning bid. However, during the process of implementation, the LCBS Project was delayed and could not be installed by the summer of 2017 as planned. The Company proposed the LCBS Project again in the 2018 plan, but due to unforeseen delays in construction scheduling and equipment availability, it was not installed and operable for the summer of 2018. Currently, the Company is still working on the LCBS Project and plans to move forward with the installation later in 2018 or early 2019 to be operable for the summer of 2019. As a result of these delays, the Company is proposing the LCBS Project as an independent effort in 2019 as area loading indicates further deferral could occur with successful load relief effort.

Considering these delays, the Company will examine the development of a risk mitigation strategy for NWAs.

The battery vendor proposes to engineer, procure, construct, and install a 1 MWh advanced battery storage solution (the Battery) designed to deliver 250 kW of peak load relief for four hours. This peak load relief need is consistent with the forecasted load growth for the Tiverton area per Section 7.1 and the Rhode Island 2018 Electric Peak Forecast Report in Appendix 1. The Battery would be located at the Tiverton Public Works Facility on Industrial Drive in Tiverton, RI. The Town of Tiverton has provided a letter of support to the vendor for this project proposal.

[17] As noted in the text, the LCBS project is now planned to be physically located in Tiverton, RI. Despite this, the Company shall maintain the title of “Little Compton Battery Storage Project” for continuity with the 2018 System Reliability Procurement Report.

The vendor's proposal is to site, own, and operate the energy storage asset, and enter into a services contract to provide the required load reduction benefit to the Company during the summers of 2019 through 2022. The Company proposes that the LCBS Project timeline span these four years, which is the maximum amount of time the substation upgrade can be deferred with this solution, based on the current peak load forecast. There is the potential for a partial NWA solution following 2022 with the LCBS Project; however, this option has not been assessed at this time. The Company requests commitment for this LCBS Project for that timeframe in order to enable a cost-effective agreement with the vendor for peak load relief services. However, the Company will make budget funding requests in each individual year, following the precedent set by the Tiverton Pilot.

Review of delays, changes in deferral value due to the Company's recently adjudicated rate case, and other factors may require the issuance of a Tiverton/Little Compton RFP (TLC RFP) in the event final contractual details cannot be resolved with the current vendor by October 1, 2018.

The Company will have the load relief project online and operational by July 1, 2019.

9.2 Project Funding Plan

The Company estimates that it will require an initial \$109,500 to implement the LCBS Project in 2019 and additional similar funds for each of the three years following. \$87,500 is associated with the actual implementation of the solution, (i.e. payments to the vendor,) and \$22,000 is associated with the management of that vendor in both implementing the solution and monitoring and evaluating it. Similar funding requests for the second, third, and fourth years of this LCBS Project will be proposed in the 2020, 2021, and 2022 SRP Reports.

9.3 Evaluation

The Company is proposing to evaluate the kW demand savings that the LCBS Project provides through a metering and control system, and the data made available through it provided by the vendor. The Company proposes that the calculation of 'demand savings'[18] shall be based on the amount of power output provided by the battery storage system during peak periods each calendar year. Evaluation shall be performed by a third-party vendor.

[18] Note that batteries have inherent losses, but the anticipation is that the battery will charge during periods of lower feeder loads and discharge during higher load times or peak load events, with the 'savings' being the load curtailment in units of kW.

9.4 Benefit-Cost Analysis

The LCBS Project's costs and savings were evaluated using the Rhode Island Test to determine whether the benefits of implementing the LCBS Project outweigh the costs.

The Company estimates that a four-year deferral will have approximately $905,197 of localized distribution investment savings for customers[19]. This value is determined by calculating the amount of revenue requirement that will not be collected if the investment is deferred for those four years. This benefit was inserted into the RI Test model as a replacement for the regional distribution benefit in the avoided costs.

The remaining benefits were estimated using the RI Test model, assuming the 250kW reduction for four hours at a time, for an estimated twenty days per year. The number of days was estimated based on the average number of days that demand response events were called in the Tiverton Pilot each year for 2015 through 2017.

The LCBS Project benefit-cost analysis differs slightly from the analysis used for the Tiverton Pilot in that the LCBS Project uses the benefits outlined in the RI Test. Conversely, the Tiverton Pilot benefit-cost analysis used the Total Resource Cost test. The LCBS Project's benefit-cost analysis is also consistent with the language in the SRP Standards section 2.3.F.

The LCBS Project budget of $438,000 represents the projected costs to procure load reduction services through the battery storage unit for a four-hour period for a contract of four years, as well as some Company resources to support the development and maintenance of this contract and load reduction events as necessary.

The following table illustrates the Benefit-Cost Analysis (BCA) of the LCBS Project using the RI Test. With a positive BC Ratio, this project represents a cost-effective solution for customers.[20]

[19]The substation upgrade was originally planned for 2014, so all benefits for this project were inflated to $2019 to match the proposed NWA Project budget.

[20] Note that the calculated BCR for the LCBS Project in this SRP Report is significantly higher than the BCR value in the 2018 SRP Report. The BCA calculation for the LCBS Project in the 2018 SRP Report had a bonus depreciation rate applied. This bonus depreciation rate was only applicable for the 2018 calendar year. Furthermore, there is no new or continued bonus depreciation rate that is applicable for the 2019 calendar year for the LCBS Project.

Table 6: Little Compton Battery Storage Project Benefit-Cost Summary

Little Compton Battery Storage Project	
Total Cost	$438,000
Total Benefits	$1,004,816
Net Benefits	$566,816
BC Ratio	2.29

10. South County East NWA Projects

The South County East NWA Projects detail new potential NWA opportunities, and the new proposal to issue RFPs to identify technologies and/or methodologies for these NWA opportunities.

10.1 Background

The South County East Area Study identified a number of potential candidates for NWA solutions to defer or eliminate a wires solution. The wires solution has been assessed and estimated and can now be compared to a NWA alternative to determine the most prudent investment to implement.

To the extent practical, each NWA candidate was developed to target a specific geographic section within the study area and to defer or eliminate a wires investment. Each area was broken down by town or sections of towns for ease of potential NWA implementation.

As mentioned in the Section 6, the Company is currently pursuing three potential NWA opportunities identified in the South County East (SCE) Area Study. These NWA opportunities are in the towns of Exeter, Narragansett, and South Kingstown.

10.1.1 Exeter

The eastern section of the Town of Exeter is supplied mostly by the Lafayette 30F2 feeder. Sections of this feeder are projected to be loaded above summer normal ratings with the limit being 4/0 aluminum conductor. This feeder has no feeder ties suitable to reduce loading below the rating of the 4/0 aluminum. Either the 4/0 Al needs to be upgraded or load must be reduced.

10.1.2 Narragansett

The Town of Narragansett is supplied mostly by (4) 12.47 kV distribution feeders. Two feeders (42F1 and 17F2) are projected to be loaded above summer normal ratings 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.

10.1.3 South Kingstown

The western section of the Town of South Kingstown is supplied mostly 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.

10.1.4 Recommendation from South County East Area Study

The recommendation from the South County East Area Study for the opportunities in the Towns of Exeter, Narragansett, and South Kingstown is to further develop the Non-Wires Option and to estimate potential implementation costs for each area. Once the cost and implementation plans are available a decision can be made on the most prudent option to implement.

The South County East Exeter NWA, South County East Narragansett NWA, and South County East South Kingstown NWA Projects shall explore these respective NWA opportunities.

10.2 Project Proposal

The Company's proposal for the 2019 calendar year is to identify technologies and/or methodologies through the RFP bid process that, when implemented, will provide an NWA solution for the specific South County East project area.

The Company is currently engaged with the Requests for Proposals (RFP) process with solution providers for project bids of NWA solutions in these areas. The Company anticipates receiving RFP responses in the first quarter of 2019.

Project build and implementation with selected vendors for the individual South County East NWA Projects shall be proposed in the 2020 SRP Report.

All three proposed projects must have a signed contract for work and the vendor will have completed their first milestone in the contract by December 31, 2019.

10.3 Projects Funding Plan

The Company estimates that it will require $30,000 to evaluate the RFP responses from solution providers.

This accounts for approximately $10,000 needed for each of the three project RFP evaluations.

11. Customer-Facing Program Enhancement Study

The objective of the Customer-Facing Program Enhancement Study is to evaluate and test novel approaches to incentivize customer behavior that can be used to address electrical distribution-level constraints and improve environmental, economic, and grid performance outcomes from residential and small commercial (R&SC) customer-facing programs.

The purpose of the proposed Enhancement Study is to develop a long-term, peak load reduction program for Rhode Island that will employ low-cost and easy-to-deploy methods to address distribution-level constraints. The Company plans to integrate learnings from the Enhancement Study in future programs and projects that engage customers in Rhode Island, because, although the Enhancement Study will focus on addressing distribution-level constraints, it is anticipated that the results of the Enhancement Study will be able to be used more broadly to improve the efficiency and cost-effectiveness of other types of customer-facing programs (e.g., Energy Efficiency, Residential Energy Storage, Electric Vehicle Charging).

11.1 Background

Connected devices, such as Wi-Fi thermostats, and home automation use connectivity, sensing, and controls to provide consumer benefits, such as enhanced comfort, control, convenience, and security, which are driving a rapid increase in adoption of these devices.[21,22,23] In addition, data from connected devices can enable new energy savings opportunities, such as equipment or appliance control and performance diagnostics. Home automation concepts have existed for decades, yet until recently have achieved limited U.S. adoption. As internet access, wireless connectivity, and smartphone ownership have become abundant in the last decade, many new connected devices (the "Internet of Things") have come to market, and their growth is projected to continue.[24] New technologies and better energy management capabilities could further increase adoption, particularly as time-varying electric rates become more common. However, the actual energy savings from these devices can vary widely because, in most cases, users must be motivated to save energy, or at least be tolerant of the energy-saving features, to realize significant benefits.[25]

[21] Parks Associates and the Consumer Electronics Association, "Smart Home Ecosystem: IoT and Consumers", 2014
[22] Icontrol Networks, "2015 State of the Smart Home Report", 2015
[23] St. John, J., "The Connected Home: Reaching Critical Mass for the Grid?", Greentech Media, May 2015
[24] Consumer Technology Association, "U.S. Consumer Technology Sales and Forecasts", January 2016
[25] Urban, B., Roth, K., Harbor, C., "Energy Savings from Five Home Automation Technologies: A Scoping Study of Technical Potential", Fraunhofer USA Center for Sustainable Energy Systems, April 2016

Beyond energy savings, connected devices offer households the opportunity to participate in utility demand response (DR) and energy efficiency (EE) programs. For example, the 2014 San Diego Gas and Electric residential peak time rebate program rewarded customers for reducing energy consumption through manual or automatic means.[26] Automatic curtailment provided an incentive of $1.25/kWh avoided, compared with $0.75/kWh for manual reductions prompted by day-ahead notifications. For the 4,000 customers participating in automated reductions, ecobee thermostats were provided and used to curtail load for four-hour periods by duty cycling central air conditioners at 50% or by implementing a 4°F setback during the same period. Consistent with other connected thermostat pilots, including the Company's own Tiverton NWA Pilot, the average event hour load reduction was about 0.5 kW per participant. Similar demand reductions were identified by the 2011 SMUD Residential Summer Solutions Study, which compared the impacts of assorted dynamic pricing, automatic load control, and energy feedback strategies.[27] In addition to connected devices and home automation, traditional customer-facing programs such as LED replacement programs and newer programs such as connected residential energy storage and behavioral demand response also have great potential to reduce peak demand. However, many of these programs have been optimized for overall energy savings rather than peak load reduction, while others are still in the early stages of customer adoption, and most have not been optimized and deployed to specifically address distribution-level constraints.

Despite their great potential, existing R&SC customer programs have struggled to achieve the level of customer enrollment, participation, and retention necessary to be effective peak load reduction tools for the utility, especially as a means to address critical distribution-level constraints. Also, the cost-effectiveness of these programs for reducing peak load has been relatively poor because they often need to reduce a significant fraction of peak load in a given area, so they need to achieve a high level of customer penetration. Such high levels of customer penetration typically require much higher marketing and/or incentive budgets to try to break through to traditional non-adopters. There have been attempts by utilities to use R&SC customer DR and targeted EE programs to address distribution-level constraints in the past with mixed success, including the Company's DemandLink program in Tiverton, Rhode Island from 2014-2017. Please refer to the Tiverton NWA Pilot Evaluation section for further information on the findings, recommendations, and results of the Tiverton Pilot.

[26] Hanna, D., Elliot, C., and Jiang, G., "2014 impact evaluation of San Diego Gas and Electric's residential peak time rebate and small customer technology deployment programs", Itron, Prepared for San Diego Gas and Electric, April 2014
[27] Herter, K., Wood, V., and Blozis, S., "The effects of combining dynamic pricing, AC load control, and real-time energy feedback: SMUD's 2011 Residential Summer Solutions Study", *Energy Efficiency*, 6:641-653, 2013

As additional background, NWA procurements for the Company's New York affiliate, Niagara Mohawk Power Corporation (NMPC) have struggled to actualize as cost-effective NWA solutions. Out of the first five NWA solicitations completed by NMPC, none have resulted in a successful NWA project to date due to very low benefit-to-cost ratios, although NMPC continues to evaluate options that might reduce the costs of these projects. A particular challenge has been finding cost-effective NWA solutions for smaller capacity needs (i.e., sub-MW peak load reductions) due to the relatively large fixed costs to install and interconnect typical NWA solutions (e.g., large-scale battery energy storage, distributed generation). The Company believes these smaller capacity projects would be a very good fit for customer-driven approaches, like DR and targeted EE, which have lower fixed costs than typical NWA solutions.

While there have been several R&SC customer DR program evaluations and improvements since the Company's Tiverton Pilot, including the Massachusetts Department of Energy Resources' (DOER) ongoing study with Fraunhofer USA[28] to evaluate how potential DR participants interact with the Company's DR website interface, there have been very few studies completed that have attempted to address the underlying motivations that would lead a person to participate in a R&SC customer DR program. Rather, there has generally been an assumption that savings/incentives are the primary motivation; but behavioral research has shown that factors such as social recognition, injunctive and descriptive norms, environmental values, and competency motivations can be just as effective, but at a much lower program cost which ultimately results in lower costs to customers. The proposed Enhancement Study will attempt to find out more about what makes potential participants engage in R&SC customer-facing programs and DR and targeted EE in particular, so the Company can better design the most cost-effective interventions.

11.2 Project Proposal

The Company proposes a multidisciplinary approach to accomplish the stated objectives. The project team will consist of subject matter experts from the Company's US Electric Business Unit, including Grid Modernization Solutions, Distribution Planning and Asset Management (DPAM), and Reliability Analytics and NWA Solutions teams; as well as the Customer Operations Business Unit, including Customer Innovation (responsible for DR programs), Customer Energy Management (responsible for EE programs) and Market Intelligence and Customer Experience teams. The internal team will be augmented with external vendors with expertise in behavioral science, customer research, and program evaluation as needed.

[28] Abreu, Joana; Voge, Jessica; McEwan, Anthony; and Roth, Kurt; "Consumer-and Market-optimized Design of Residential Demand Response Programs using Connected Devices"; Fraunhofer USA DRAFT Interim Report – Usability Study results to Massachusetts DOER; July 2017

The Company envisions a three-phased approach, with Phases 1 spanning year 1, and Phase 2 and 3 spanning subsequent years. In Phase 1, the Company will conduct a solicitation for external vendor(s) with expertise in behavioral science and customer research. The vendor(s) will be used to develop, test, and select novel customer engagement approaches that have the greatest potential to increase enrollment, participation, and retention in R&SC customer peak load reduction programs at the lowest cost. In Phase 2, the Company will select a pilot location and develop a peak load reduction pilot program plan to specifically address a critical distribution-level constraint. It is anticipated that Phase 2 will be a 3- to 6-month effort and will involve input from external stakeholders, including the Collaborative. In Phase 3, the Company will evaluate and test the novel customer engagement approaches using the pilot location selected in Phase 2. The approximately two and a half years proposed for Phase 3 will provide an opportunity to experimentally test a variety of new approaches developed in Phase 1 and fine-tune the peak load reduction program developed in Phase 2. Phases 1, 2, and 3 will employ an iterative approach to test multiple methods and optimize the peak load reduction program plan.

11.2.1 Phase 1: Program Plan

Phase 1 will leverage lessons learned from existing R&SC customer programs, including the Company's Tiverton Pilot, evaluate residential energy storage and other new programs that could potentially be more effective and reliable for reducing peak loads, and use RI-specific demographics to develop a *R&SC Customer Peak Load Reduction Program Enhancement Plan* (Program Plan) for the State. The Company's current R&SC customer peak load reduction program, ConnectedSolutions, which is the successor program to DemandLink, has already undergone several significant program improvements, including marketing and user experience improvements based on usability testing conducted by Fraunhofer USA, and a "Bring Your Own Battery" option where DR participants can connect their EV charger or stationary energy storage system to the ConnectedSolutions platform. The Company also has significant experience with traditional EE programs, like LED replacement programs, which have been shown to be effective at reducing peak demand. The Company will consider optimization of these and other control-based and information-based peak load reduction enabling technologies for evaluation in the proposed pilot.

In addition to leveraging the Company's R&SC customer DR and EE experiences, a vendor(s) with behavioral science and customer research expertise will perform a thorough literature review and use the lessons learned from other customer peak load reduction programs, direct assessments, and RI customer demographics, to develop novel customer engagement approaches based on behavioral economic and other behavioral science principles that are designed to increase customer enrollment, participation, and retention for R&SC customer classes. Qualitative (e.g., focus groups, interviews) and quantitative (e.g., surveys, experiments) direct assessments will be used to learn more about the obstacles, values and other motivations that are driving customer behavior around use of electricity. Novel approaches could include economic and non-economic motivations for behavior, based on accepted models of human behavior and social marketing. This may include approaches such as behavioral nudges, social recognition and peer leadership, and programs to increase perceived efficacy and behavioral control. More specifically, the proposed Enhancement Study could explore a combination of dynamic tariff structure with different levels of information and/or nudges as an effective way to increase participation and couple it with the implementation of a loyalty program (rewards for longevity or efficiency) to retain customers. The novel approaches will be incorporated into a comprehensive Program Plan for the State.

Phase 1 will involve six tasks, including:

1. **Solicitation** for outside vendor(s) with expertise in behavioral science and customer research including development of the potential vendor list and RFP documentation, solicitation, proposal review, vendor selection, and contract negotiation.

2. **Literature Review** (trade and academic research) of customer engagement approaches designed to improve customer responsiveness (e.g., behavioral nudges, social recognition, peer leadership, injunctive and descriptive norms, environmental values, and competency motivations); peak load reduction programs; and peak load reduction technologies.[29]

3. **Customer Research** to determine customer demographics, energy usage, and segmentation; estimate customer program participation/technology adoption and propensity analysis; and conduct customer surveys or focus groups to gain specific insights into obstacles, values and other motivations that are driving customer behavior around use of electricity.

4. **Technology Ranking** based on a weighting of program goals and technology/program analyses including time value analysis (e.g., potential for peak load reduction measure to meet hourly/seasonal feeder need, GHG reduction goals, etc.), performance analysis (e.g., potential for peak load reduction measure to meet capacity feeder need), and ranking peak load reduction measures for each customer segment based on the weighted program goals.

[29] Peak load reduction enabling technologies could include smart thermostats, heat pump cooling, solar, heat pump water heaters, electric vehicle charging, home energy storage, Wi-Fi electric water heaters, connected home devices, home energy monitors, targeted LED lighting, and automated window coverings.

5. **Customer Testing** using customer surveys or focus groups to assess the customer engagement approaches and peak load reduction measures evaluated and selected in Tasks 1-3.

6. **RI Peak Load Reduction Program Plan** that summarizes the results of Tasks 1-4, makes final recommendations based on internal subject matter expert and external stakeholder review, and delivers a *R&SC Customer Peak Load Reduction Program Enhancement Plan* (Program Plan) for the State.

The Company shall issue a bid for solicitation to third-party vendors and circulate an initial version of the Program Plan with the Collaborative by December 31, 2019.

11.2.2 Phase 2: Pilot Implementation Plan

Phase 2 will engage the Company's subject matter experts to select a favorable pilot location in order to field test the novel approaches developed in Phase 1. Selection will be based on the potential for peak load reduction measures to address a specific distribution-level need and will include factors such as customer classes, housing profiles, utility access, income levels, and other demographics specific to areas in Rhode Island with particular electrical distribution-level constraints as indicated by the map resources presented on the Company's Rhode Island System Data Portal.[30]

Next, the Company will develop a *R&SC Customer Peak Load Reduction Pilot Implementation Plan* (Pilot Implementation Plan) to specifically address distribution-level peak loads in the selected area based on the novel customer engagement approaches developed in Phase 1. It is anticipated that the Pilot Implementation Plan will involve input from external stakeholders, including the Collaborative, and will consider the possible synergistic effects of bundling the peak load reduction program with other programs offered by the Company, including the Community Initiative, Home Energy Reports, and Energy Efficiency Retrofit Programs (e.g., EnergyWise single family retrofit program).

Finally, the Company will work with subject matter experts, the Collaborative, and selected third-party vendors to develop performance metrics and an evaluation plan to gauge the success of the field testing to be conducted in Phase 3. Metrics may include the cost-effectiveness of enrollment, participation, retention, scalability, customer satisfaction, and capability to reduce peak demand to help address specific electrical distribution-level constraints.

[30] Note that it is not the intent of the project to demonstrate that customer-facing programs, and customer DR in particular, can solve all distribution-level problems, but rather that they can be effective tools to help reduce peak demand, particularly as the Company develops better communication with its customers and increasing numbers of customers' appliances, and loads in general, become connected.

11.2.3 Phase 3: Enhancement Study Pilot Testing

Phase 3 will evaluate and test the novel customer engagement approaches in the Pilot Implementation Plan using the pilot location selected in Phase 2. The Company will work with existing DR and EE program administrators, and procure additional third-parties as needed, to deploy the peak load reduction technology, marketing, engagement, and retention measures outlined in the Implementation Plan. The Company will also work with selected third parties to develop an evaluation plan, perform measurement and verification (M&V) and evaluation of pilot results, and make future recommendations based on the performance metrics established in Phase 2 and lessons learned from the pilot deployments.

11.3 Schedule

If approved, the proposed Enhancement Study would commence on January 1, 2019. Phase 1 would require twelve months. It is anticipated that Phase 2 and 3 would require an additional three years to test various peak load reduction enhancement approaches with various customers in the pilot area, but the duration and timeline will be finalized at the end of Phase 1. To ensure the most efficient and cost-effective project possible, the Company will make two Go/No-Go decisions after completing key deliverables in Year 1:

1. June 30, 2019: Go/No-Go for Phase 1 Task 3 survey/focus group implementation after completion of the customer survey design and review.

2. December 21, 2019: Go/No-Go for Phase 2 after completion of the draft Program Plan with details regarding methods, findings, and recommendations.

Table 7: Enhancement Study Phase 1 Schedule

Phase 1 Schedule	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Solicitation	■	■										
Literature Review			■	■								
Customer Research					■	◊	■					
Technology Ranking					■	■	■					
Customer Testing								■	■	■		
Program Plan											■	◊

◊ = Milestones
■ = Planned Timeline

11.4 Program Funding Plan

The Company estimates that it will require $175,000 to implement Phase 1 of the Enhancement Study in 2019. Of this amount, $100,000 is estimated for third-party vendors to complete the Literature Review, Customer Research, and Customer Testing tasks and $75,000 is estimated to complete the Solicitation, Technology Ranking, and

Program Plan tasks in addition to program planning and management by National Grid staff.

Specific funding requests for Phase 2 and 3 of this Enhancement Study will be proposed in subsequent SRP Reports.

11.5 Evaluation

The Company is proposing to work with a third-party vendor for the impact and process evaluation in Phase 3. A specific evaluation plan will be determined by the end of Phase 2, but evaluation criteria may include peak demand reduction load, duration and frequency capabilities; and peak load reduction program enrollment, participation, retention, customer satisfaction, and overall cost-effectiveness. The first year of the project will be evaluated using updated BCA calculations based on the results of Phase 1.

11.6 Benefit-Cost Analysis

The Enhancement Study is primarily research, development and demonstration during Phases 1 through 3. In the ten years following Phase 3 (2023 through 2032), the Company plans to integrate learnings from the Enhancement Study in future programs and projects that engage customers in Rhode Island. Therefore, a BCA calculation was performed for the initial Enhancement Study period (2019-2022) plus an additional 10-year period (2023-2032) over which time it is assumed a future Rhode Island peak load reduction enhancement program (Enhancement Program) will be deployed in other locations to address additional distribution-level constraints. Other EE or DR program benefits were not included in the BCA for simplicity, but are expected to be realized if the Enhancement Study is successful. Although it is not known in advance what kinds of distribution-level constraints will be discovered in future distribution area studies, it is assumed they will be of similar scale and cost for the traditional solution (i.e., Wires Option) as the three NWA opportunity areas identified in the South County East (SCE) Area Study Distribution Planning exercise, which resulted in a new peak load relief need of 5.4 MW. The deferral period for both the Enhancement Study pilot and future Enhancement Program is assumed to be 10 years.

For the purposes of the BCA calculation, the Company estimates that it will require $285,000 annually to implement Phase 2 and 3 in each of the remaining years of the project. $50,000 is estimated for new participant incentives; $65,000 for program planning and management; and $170,000 for marketing, advertising, and evaluation each year. New participant incentives for Phases 3 assume $150 per participant household for the purchase of a Home Energy Monitoring system[31] and $160 per kW of peak load relief incentive for the connected device, which would allow for new incentives of $100 per device for connected thermostats and up to $580 per device for connected energy storage systems.[32] Existing incentives, which are included in the BCA but not in the Program Funding Plan estimate because they are included in the EE budget, are estimated from our existing residential DR program (e.g., $20 for ConnectedSolutions sign up and $25 per year for ConnectedSolutions participation). These incentive assumptions are for budget forecasting and BCA purposes only.

The RI Test BCA for the Enhancement Program, that will employ the low-cost and easy-to-deploy methods developed by the proposed Enhancement Study, calculates an estimated BCR of 1.96. The total benefits and costs associated with both the proposed Study and the future Program summed over the assumed 14-year period results in a BCR of 1.73, while the Net Present Value (NPV) of all the benefits and costs over the 14-year period results in a BCR of 1.68.

Table 8: Enhancement Study BCA Summary – Base Case

Projected Enhancement Study + Program Benefits and Costs - Base Case	Total (14-Yr)	NPV (14-Yr)	Phase 1	Phase 2 and 3			Program
			2019	2020	2021	2022	2023-2032 Average
New Peak Load Reduction Addressed, kW	17,800	-	-	100	300	300	1,710
% Total New Peak Load Reduction Need			0%	2%	5%	5%	30%
Number of New Connected Devices	16,310	-	-	92	275	275	1,567
Total Benefits	$12,580,160	$ 6,763,699	$ -	$ 61,104	$ 186,977	$ 190,717	$1,214,136
Enhancement Study Costs	$ 1,030,000	$ 861,719	$ 175,000	$ 285,000	$ 285,000	$ 285,000	$ -
Enhancement Program Costs	$ 3,328,959	$ 1,758,236	$ -	$ -	$ -	$ -	$ 332,896
Existing DR Program Costs	$ 2,905,119	$ 1,402,084	$ -	$ 2,383	$ 9,723	$ 17,356	$ 287,566
Total Study + Program Costs	$ 7,264,077	$ 4,022,039	$ 175,000	$ 287,383	$ 294,723	$ 302,356	$ 620,461
BCR	**1.73**	**1.68**	**-**	**0.21**	**0.63**	**0.63**	**1.96**

**Costs and benefits include 2% annual inflation*

The BCA calculation assumes 700 kW of peak load relief is addressed by the end of the Enhancement Study (Phase 3) resulting in a 10-year deferral of one traditional distribution wires solution by 2022. For the next 10 years, it is assumed a future Enhancement Program can address 1.71 MW of new peak load relief each year with similar traditional wires solution costs deferred each year. Ongoing Enhancement Program costs assume $160 per kW of peak load relief incentive for the connected

[31] Note that it is assumed a Home Energy Monitoring System would not be needed after the Study period (>2022), but if detailed home energy information is still necessary, the Company should have completed deployment of AMI by 2023 and can leverage that information for future program implementation.

[32] For cost estimating purposes, it is assumed 50% of the annual peak load relief is addressed through connected thermostats and 50% is addressed through connected home energy storage, although costs could be different for other devices and programs that will be contemplated in the Study.

device. This level of new incentive would allow for $100 per device for connected thermostats and up to $580 per device for connected energy storage systems.

Existing DR program costs include a $20 one-time ConnectedSolutions bill credit at sign-up and $25 per year for annual ConnectedSolutions participation. All cost and benefit estimates include 2% annual inflation. Cost estimates do not include economies of scale, learning by doing, or other annual cost reduction assumptions. These cost assumptions are considered relatively conservative given the stated cost-minimization goal of the Study.

The Company used typical assumptions throughout the estimated future cost and benefit estimates in the base case BCA. One remaining uncertainty is the total amount of peak load reduction capacity (i.e., New Peak Load Reduction Addressed per the following table) that can be addressed by the future Program.

The Company developed a more conservative case to evaluate this uncertainty. This conservative case assumes the future Enhancement Program only addresses 570 kW of new peak load relief each year for 10 years, which is half the Base Case assumption of 1.71 MW. In this conservative BCA, the Enhancement Program BCR is estimated to be 1.84, the overall BCR for the 14-year period is estimated to be 1.38, and the NPV BCR is estimated to be 1.24.

Table 9: Enhancement Study BCA Summary – Conservative Case

Projected Enhancement Study + Program Benefits and Costs - Conservative Case	Total (14-Yr)	NPV (14-Yr)	Phase 1	Phase 2 and 3			Program
			2019	2020	2021	2022	2023-2032 Average
New Peak Load Reduction Addressed, kW	6,400	-	-	100	300	300	570
% Total New Peak Load Reduction Need			0%	2%	5%	5%	10%
Number of New Connected Devices	5,864	-	-	92	275	275	522
Total Benefits	$ 4,485,919	$ 2,488,612	$ -	$ 61,104	$ 186,977	$ 190,717	$ 404,712
Enhancement Study Costs	$ 1,030,000	$ 861,719	$ 175,000	$ 285,000	$ 285,000	$ 285,000	$ -
Enhancement Program Costs	$ 1,109,653	$ 586,079	$ -	$ -	$ -	$ -	$ 110,965
Existing DR Program Costs	$ 1,117,247	$ 551,104	$ -	$ 2,383	$ 9,723	$ 17,356	$ 108,778
Total Study + Program Costs	$ 3,256,900	$ 1,998,901	$ 175,000	$ 287,383	$ 294,723	$ 302,356	$ 219,744
BCR	**1.38**	**1.24**	**-**	**0.21**	**0.63**	**0.63**	**1.84**

**Costs and benefits include 2% annual inflation*

Total benefits for the Enhancement Study and Enhancement Program for both the base case and conservative case are based on the 2010 benefits and factors of the RI Test for the Company's ConnectedSolutions Residential DR program, which can be found in the Company's 2019 EE Plan. Note, however, that benefits could be different for other devices and programs that will be contemplated in the Study.

Table 10: Benefit Summary for Residential Demand Response Program

Residential ConnectedSolutions Annual Benefits		**Benefit**	**Benefit per kW load red.**
Capacity	Summer Generation	$ 33,030	$ 21.12
	Capacity DRIPE	$ 554,083	$ 354.28
	Transmission	$ 166,138	$ 106.23
	Distribution	$ 144,458	$ 92.37
	Reliability	$ 20,136	$ 12.88
Electric Energy	Summer Peak	$ 166	$ 0.11
	Summer Off Peak	$ 108	$ 0.07
	Electric Energy DRIPE	$ 152	$ 0.10
Non-Electric Benefits		$ -	$ -
Societal	Carbon Benefits	$ 246	$ 0.16
Total Benefits		**$ 918,517**	**$ 587.31**
Load Reduction	Summer	1,564	1.00
kWh Saved	Annual	7,685	4.91

12. Rhode Island Locational Incentives

The Company proposes to provide an incentive for bidders to respond to when the South County East NWA RFPs are issued in late 2018, per the 2018 SRP Report. This proposal is discussed further in this section, but first it is also important to understand the analysis on locational incentives that the Company undertook in 2017.

12.1 Summary of the Company's Locational Incentive Analysis in Rhode Island in 2017

The Company's locational incentive research and analysis was conducted in 2017 under the option the Company should offer a location incentive as per the RE Growth program with stakeholder engagement from the Division and OER. The analysis followed a three-phase approach: 1) expedited method for screening feeders and peak analysis; 2) three approaches to understanding potential avoided cost benefits and 3) solar contribution to load reduction. The second step encompassed three different approaches to estimate potential benefits from load relief, both broadly and at specific locations: 1) system-wide avoided transmission and distribution cost; 2) feeder-specific deferral value of distribution system upgrades as measured by the avoided revenue requirement NPV, multiplied by the probability of a spot load developing necessitating an upgrade; 3) time-value deferral NPV, similar to what has been used for the SRP area. A copy of the locational incentive analysis presented to the Rhode Island Division and OER on September 12, 2017 is provided as Appendix 5.

12.1.1 Feeder Screening

The first step in the locational analysis performed in 2017 was to conduct an analysis of feeders and substations in Rhode Island based on loading, asset condition, and expected growth to provide a reasonable basis on which to consider Locational Incentives within the RE Growth Program. The following screening criteria were used in the Rhode Island analysis: feeders loaded at least 80% in the last year; the asset must not be scheduled for upgrade due to asset age or condition; and load on the asset must be growing, based on load forecasting results. These criteria are similar to the criteria used in the New York Marginal Avoided Distribution Capacity (MADC), which is explained further in Appendix 6. The result of this analysis in Rhode Island was a list of 25 feeders that passed the screening criteria.

Of these 25 feeders identified, 20 had hourly data that was immediately available in a form ready to be analyzed. These 20 feeders were then further analyzed to identify their peak hour times. The top three percent of hours by kVA on each feeder were sorted by hour for historical 2015 and 2016 years. The resulting analysis shows that these feeders fall into two groups that peak at different times, with one group peaking early, and a second group peaking later. Page 6 in Appendix 5 shows the peak hours by feeder. The time of peak significantly impacts the potential value that solar can provide to reduce loading, and thus the amount of incentive it might earn.

While some of these feeders are heavily loaded, zero are scheduled to be upgraded in the next three years and none are predicted to reach 100% loaded by 2027, except for those in the Tiverton Pilot. In other words, none of the feeders were forecasted to be constrained within our three-year planning horizon and criteria, and there is no cost to defer. Spot/pop-up loads can occur and cause feeder upgrades, but this happens in an unpredictable manner and location, making it not possible to tie to a locational incentive. A spot load represents the load that a commercial and industrial (C&I) or residential facility, residence, or property creates on an electrical distribution network; it is an electrical load that occurs in one specific spot or location on an electrical distribution network. Approximately one percent of feeders require an upgrade annually due to spot/pop-up loads and the forecast does not predict these. Once the spot load occurs and influences the load, that becomes the basis in the next forecast.

Because the analysis found that there were no constraints and no costs to avoid, the Company deferred implementing a Locational Incentive program. However, the Company did outline how it could design and calculate a potential locational incentive if forecasts point to constraints in the future. That process is outlined below and in Appendix 5 and it is still the process the Company proposes to use if forecasts point to constraints in the future outside of the South County East NWA projects.

12.1.2 Understanding Potential Avoided Cost Benefits

The Company examined three different approaches to estimate potential benefits from load relief: 1) System-wide Avoided Transmission and Distribution Cost; 2) feeder-specific deferral value of distribution system upgrades as measured by the avoided revenue requirement NPV, multiplied by the probability of a spot load developing and necessitating an upgrade; and 3) Time-Value deferral NPV, similar to what has been used for the SRP area.

The first approach, the Avoided Transmission and Distribution (T&D) Cost approach, is a system-wide approach that looks at historic and forecast summer peak impacts for T&D. During the 2017 analysis, the Energy Efficiency Avoided T&D Cost estimate showed the marginal cost of T&D capacity to be a combined $93.16/kW per year. However, when expected Energy Efficiency and DG program impacts are included in the forecast, the forecast growth spend dollars are naturally spread over much fewer MWs of growth, due to minimal load growth in Rhode Island. This results in a lower $/kW per year value and the Company concluded that this approach does not provide a useful measure of the location-specific cost of growth to be considered when examining a post-Energy Efficiency and post-DG program forecast.

The second approach calculated feeder deferral costs. The Company used the same 20 feeders that were identified in the first phase of the analysis. As stated earlier, these feeders are heavily loaded, but they are not scheduled to be upgraded in the next three years, and do not appear to reach 100% in the next 10 years based on current load forecasting, except for those in the Tiverton Pilot. In order to relieve constraints, in some circumstances, two- or three-mile segments of feeders must be replaced. This analysis used a base case of a one-mile upgrade. In addition, the occurrence of a constraint and its location is uncertain; however, only approximately 1% of feeders require upgrades annually due to spot/pop-up loads. The analysis used two methods to estimate deferral values for this infrastructure: 1) Method 1: Probability-weighted avoided revenue requirement NPV. Over a 10-year deferral period, this would provide a probability weighting of approximately 10% of the avoided revenue requirement NPV; and 2) Method 2: a ten-year deferral of full revenue requirement, where the difference in NPV between building an upgrade now or in 10 years was calculated. The calculated deferral costs, by feeder and for each method, are shown on page 11 in Appendix 5.

Lastly, the third approach used to understand potential avoided cost benefits was a Time-Value deferral NPV, similar to what has been used for the SRP area.

12.1.3 Solar Contribution to Load Reduction

During the next phase of the analysis, the Company used historical solar data to understand the benefits that solar photovoltaics (PV) could provide to the distribution system. Solar PV output is the result of system losses and solar insolation, driven by latitude, cloud and snow cover, shading, and orientation and degree of tilt. National Grid partnered with Peregrine Energy to study solar contribution to distribution load relief in 2014 in the Tiverton Pilot area. The study coined the term Distribution Contribution Percentage, meaning the capacity factor for solar systems over the peak period. In the 2017 analysis, the Company analyzed solar output by hour and categorized the summer months (June through September) into two time periods that represented where the feeder peak hours aligned: Group A (1pm- 4:59pm) and Group B (4-7:59pm). The solar output data was sourced from the National Renewable Energy Laboratory’s (NREL’s) PVWatts® Calculator. These four hours of peaking were multiplied by the four summer months, and again multiplied by an average of 30 days each, which results in a total Summer Capacity Factor of 480 peak hours. Using the same math, the single Monthly Capacity Factor is 120. Both the total Summer Capacity Factor and individual summer months Capacity Factor were calculated for each azimuth using the following calculation:

$$Summer\ Capacity\ Factor = \frac{Sum\ of\ kWh\ Solar\ Output\ in\ Group}{\frac{(Hours\ in\ Group)\times(Days\ in\ Month)}{1000}}$$

The four summer months were then totaled to reach a total Summer Capacity Factor by azimuth. Below is an example of the calculation performed for last year, using the following data:

Table 11: Summer Capacity Factor Data for Calculation

Average kWh by Hour, Summer Only – 180° azimuth	Group A		Group B	
	Sum of kWh solar Output	Capacity Factor	Sum of kWh solar Output	Capacity Factor
June	44,691	37.24%	9,382	7.82%
July	48,534	40.45%	10,600	8.83%
August	45,948	38.29%	7,873	6.56%
September	33,983	28.32%	3,900	3.25%
Summer Capacity	173,157	36.07%	31,754	6.62%

$$Group\ A\ Summer\ Capacity\ Factor\ June = \frac{44{,}691}{\frac{4\times 30}{1000}} = 0.3724 = 37.24\%$$

The Company examined lost revenue by azimuth and system size and found that south-facing systems produce more total energy. However, west-facing systems produce more energy late in the afternoon, which is more closely aligned with peak system, and is when it can provide added value.

Employing the same Method 1 and Method 2 from the feeder deferral costs analysis, Method 2 Adders do not make up lost base revenue for small systems. Page 22 in Appendix 5 shows a sample early peaking feeder and a sample late peaking feeder to support this conclusion. For a large system, Method 2 would almost be large enough to justify 210 degrees, and Method 1 is close to making up for lost revenue at 210 degrees. The numbers that led to this conclusion are on page 23 and 24 of Appendix 5.

The Company then proposed potential approaches to a locational incentive structure. One approach is to distribute the annual deferral value over the total annual avoided peak demand (i.e., kilowatts that are generated or reduced by distributed energy resources). Lump sum payments or annualized payments are possible. Lump sum payments more closely mimic installation costs and would be applied to smaller projects less than 25 kWh without interval meters. This would be a per-kW of peak production payment and actual incentives would be scaled by predicted system production during the predicted peak periods. Annualized payments ($/kWh value) based on the actual DER output during the actual peak periods better incentivize actual performance.

No locational incentives were proposed in the 2018 RE Growth filing due to the lack of specific NWA opportunities.

12.2 Current Status of Distributed Generation Growth in Rhode Island

Rhode Island has a long, successful history at offering solution providers multiple paths by which to install DG in the state. RE Growth, existing feed in tariffs, and rebates on CHP are all paths that Rhode Island customers can utilize. As presented at the Rhode Island Quarterly DG Interconnection Meeting in July 2018, interconnection trends for both DG applications received (number of applications and megawatts) and for DG interconnected (number of applications and megawatts) have trended upwards since 2011. This trend is applicable to both complex and simple projects.

Table 12: Rhode Island Complex Interconnection Application Trends

Received Applications, Complex			Interconnected Applications, Complex	
	MW	Apps	MW	Apps
2011	25.0	27	1.0	8
2012	36.0	60	7.2	12
2013	23.0	53	13.3	19
2014	23.2	47	17.8	22
2015	58.9	102	3.3	27
2016	134.2	139	21.1	52
2017	297.3	149	23.8	55
2018	349.9	161	5.5	27
Total	947.6	738	93.0	222

Table 13: Rhode Island Simplified Interconnection Application Trends

Received Applications, Simple			Interconnected Applications, Simple	
	MW	Apps	MW	Apps
2011	0.2	30	0.2	21
2012	0.2	41	0.3	45
2013	0.3	77	0.2	51
2014	0.6	127	0.4	77
2015	3.2	599	1.9	329
2016	10.1	1,724	8.1	1,351
2017	12.6	2,237	10.8	1,832
2018	7.7	1,313	4.4	774
Total	34.8	6,148	26.4	4,480

12.3 Current Status of Electric Peak Load in Rhode Island

Although the Locational Incentive analysis was performed in the summer of 2017, the current Rhode Island 2018 Electric Peak (MW) Forecast for the long-term (2018-2032),[33] provided in Appendix 1, continues to support the conclusion that the Rhode Island service territory is not experiencing load growth. The service territory is experiencing negative growth of -0.1% annually over the next fifteen years. From pages 4 to 5 of the Rhode Island 2018 Electric Peak (MW) Forecast:

> "Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electrical 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 2017 was 1,688[34] , on Thursday, July 20th at hour-ending 16. The 2017 peak was 15% below the NECO all-time high of 1,985 MW reached on Wednesday, August 2, 2006.
>
> This summer's [2017] peak weather was considered cooler than normal (average). This year's peak is estimated to be 35 MW below 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 1,723 MW, a decrease of -3.1% vs. last year's weather-adjusted 'normal' peak.
>
> The forecast indicates that the overall service territory will experience negative growth of -0.1% annually over the next fifteen years, primarily due to the impacts of energy efficiency and solar PV offsetting any underlying economic growth."

The Company presented at the Rhode Island Quarterly DG Interconnection Meeting in July 2018 that, by the end of 2018, the Company forecasts that Rhode Island's electric load will be reduced by 1.2% from historical load levels. This reduction is based on an assumption of solar DG having a 21% annual average capacity factor and forecasted 25 MW of solar. By the end of 2019, the Company forecasts that Rhode Island's electric load will be reduced an incremental 0.4%, assuming 21% annual average capacity factor

[33] Gredder, Joseph F, and Pedram Jahangiri. "Rhode Island 2018 Electric Peak (MW) Forecast; Long-Term: 2018 to 2032." *Rhode Island System Data Portal*, National Grid, 10 Jan. 2018, http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_Forecast_PEAK_2018_Report_rev1_Jan2018.pdf.
[34] Meter Data Service's system level preliminary peak and subject to change

and forecasted 32 MW of solar. In comparison, load growth in National Grid's New York service territory is estimated to be 0.1%.

Please see Appendix 6 for a description of the process to determine locational values as part of the New York Public Service Commission's Case 15-E-0751.[35] The intent was to develop a replacement for net metering to provide a large enough subsidy to promote renewable DG. Rhode Island is not looking to replace net metering. Therefore, the need for such a similar process is not needed.

12.4 Proposal for Locational Incentives in Rhode Island

The Company proposes to further the work from last year's effort by using the deferral value for specific NWA locations at South County East to provide an incentive for bidders to respond to when the NWA RFPs are issued late in 2018 as per the 2018 SRP Report. In order to provide value back to customers, the Company initially suggests using no more than 60% of the deferral value on an annualized basis over the term of the deferral need, then estimating the number of kilowatt-hours needed in a location (load relief needed in kilowatts multiplied by the estimated hours the load relief is needed over the term of the deferral need) and calculating a per-kWh credit to be paid based on performance of the winning bidder's project or program. The specific details of this calculation are ongoing as they are part of the larger project to issue new RFPs for the SCE NWA projects which will not be released until later in calendar year 2018. The Company would determine the proper avenue for proposing such an incentive and appropriately file for approval to pay these incentives showing the projects the Company expects to fund with the incentives.

12.5 The Future of Locational Incentives in Rhode Island

Under the Rhode Island Power Sector Transformation, the Rhode Island Public Utilities Commission approved the Company's Settlement Agreement with modifications. Included in the Settlement Agreement is the approval of an electric transportation initiative in Rhode Island. Additionally, the Decision provides that the utility must include opportunities for Electric Vehicles in distribution level planning. While factors such as advances in energy efficiency, distributed solar, and behind-the-meter storage decrease utility load, the electrification of transportation and heat are expected to reverse that trend. One report that supports this trend is the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) 2018 report, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the*

[35] Case 15-E-0751 *et al*., *In the Matter of the Value of Distributed Energy Resources et al*., Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Phase One Order").

United States[36]. This report is the second publication in a series and presents scenarios of electric end-use technology adoption and resulting electricity in the United States. The scenarios in the report reflect a wide range of electricity demand growth through 2050 that result from various electric technology adoption and efficiency projections in the transportation, residential and commercial buildings, and industrial sectors. Their analysis examined three scenarios and the results from all three scenarios predict steady demand growth across the next three decades, largely driven by the adoption of electric vehicles.

The expected increase in DC Fast Charging that results from the Power Sector Transformation electric transportation initiative and Rhode Island's Zero Emission Vehicle (ZEV) Draft Plan goals for growing EV adoption more than 40-fold by 2025 must be managed with appropriate electrical service and distributed generation and storage resources to effectively prevent system overloading and to avoid utility peak demand charges. The Company does see an opportunity in the future to offer locational incentives in locations where load on the electric distribution system is increasing due to the growth of EVSE and electric heat.

[36] Mai, Trieu, Paige Jadun, Jeffrey Logan, Colin McMillan, Matteo Muratori, Daniel Steinberg, Laura Vimmerstedt, Ryan Jones, Benjamin Haley, and Brent Nelson. *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500. https://www.nrel.gov/docs/fy18osti/71500.pdf

13. SRP Incentive Mechanism Proposal

The Company and the Parties have agreed on a proposal comprised of a combination of action-based and savings-based metrics for the Company to earn incentives on work completed through SRP in 2019.

13.1 Action-Based SRP Incentives for 2019

The Company will earn an incentive equal to a portion of the 2019 SRP budget for completing certain actions, as described in this Report, by the milestone date stated in this Report. The actions and associated percentages of the 2019 SRP budget the Company can earn are:

Table 14: Summary of Action-Based SRP Incentives

Section	Action	Date	% of 2019 SRP Budget
Rhode Island System Data Portal	Further Enhancement of Portal for Optimal Level 3 EV Charging Locations	July 1, 2019	2%
South County East NWA Projects	Awarded and Completion of First Milestone for All 3 Projects	December 31, 2019	2%
Customer-Facing Program Enhancement Study	Issue Bid and Completion of Phase 1 Deliverable	December 31, 2019	2%

Accordingly, if the Company were to implement all the initiatives referenced above by the dates defined in this Report, it would earn a maximum of 6% of the 2019 SRP budget. The 2019 SRP budget would be defined as all the costs required to implement the SRP initiatives described above. This SRP budget would be determined in the SRP Report, prior to the commencement of 2019 SRP activities. The amount of SRP incentives earned would be based on this initial budget, not on the actual dollars spent to implement the initiatives.

13.2 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 15: Summary of Action-Based 2018 SRP Report Incentives

Section	Action	Date	% of 2018 SRP Budget
Rhode Island System Data Portal & Heat Map Resources	Complete an Initial Version of the Portal	June 30, 2018	1%
Rhode Island System Data Portal & Heat Map Resources	Complete DG-Focused Map	September 30, 2018	1%
Rhode Island System Data Portal & Heat Map Resources	Complete a Stakeholder Review Process of Location-Based Avoided Costs	August 31, 2018	1%
Market Engagement with NWAs	Develop and Deploy an Initial Marketing & Engagement Plan	March 31, 2018	1%
Rhode Island System Data Portal & Heat Map Resources	Issue at least two new RFPs for NWA Resources	December 31, 2018	2%

Regarding the potential incentive earnings to date, the status and calculation is detailed as follows:

- To date, the initial version of the Portal has been completed by June 30, 2018 and an initial version of the Marketing & Engagement Plan has been developed and deployed by March 31, 2018.
- The DG-Focused map component of the Portal is still in development and two new RFPs for NWA resources have not yet been issued.
- The stakeholder review process of location-based avoided costs had not been completed by the assigned date.
- The 2018 SRP Plan budget spend to date is $175,602.
- The total achieved percentage of 2018 SRP budget to date is 2%.
- Therefore, the total potential incentive earnings to date is calculated to be approximately $3,512.

These action statuses and calculated earnings are illustrated in the table below.

Table 16: Summary of 2018 SRP Report Incentives Earnings to Date

SRP Incentive Item	Action Completed?	% of 2018 SRP Budget	Calculated Earnings
Complete an Initial Version of the Portal	Yes	1%	$1,756
Complete DG-Focused Map	On Track, Not Yet	1%	N/A
Complete a Stakeholder Review Process of Location-Based Avoided Costs	No	1%	N/A
Develop and Deploy an Initial Marketing & Engagement Plan	Yes	1%	$1,756
Issue at least two new RFPs for NWA Resources	On Track, Not Yet	2%	N/A
		Total Earn to Date	**$3,512**

Earnings on 2018 SRP Report incentive actions will be requested in the 2020 SRP Report, since the full 2018 calendar year will be complete and assessed by the time of the 2020 SRP Report.

13.3 Savings-Based SRP Incentives

The Company will also be able to earn savings-based incentives for those DERs that are installed as a result of the SRP initiatives described above. The Company will be obligated to demonstrate that DERs were installed as a result of the SRP initiatives. 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 plan (i.e. calendar year 2019). In future SRP plans (2020 and on), there will be a third requirement: 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 them, 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 will be defined 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.

In 2019, the net benefits of the DERs will be shared by allocating 20% to the Company and 80% to customers. The savings-based incentive mechanism would be applied to the net benefits of the LCBS Project proposed in this 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. The proposed 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 LCBS Project proposed in this Report.

LCBS Project Net Benefits[37]:	$566,816
Company Incentive Share:	20%
Company Incentive:	$113,363

The Company has not included a budget line item for incentives in this SRP Report. Any incentive earned by the Company will be calculated and included as part of the 2020 SRP Report funding request.

[37] From page 36 of this Report

14. 2019 System Reliability Procurement Funding Request

The Company proposes to fund the projects and initiatives included in this SRP Report through the energy efficiency 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 2019.

Table 17: Summary of 2019 SRP Funding Request

SRP Initiative	Cost
Marketing & Engagement Plan	$124,800
Little Compton Battery Storage	$109,500
Customer-Facing Program Enhancement Study	$175,000
South County East RFP Evaluation	$30,000
Total	**$439,300**

Table S-1: RI SRP 2019 Funding Sources

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

		2019
(1)	**2019 SRP Budget**	**$439.3**
(2)	**Projected Year-End Fund Balance and Interest:**	**$574.6**
(3)	**Customer Funding Required:**	**-$135.3**
(4)	**Forecasted kWh Sales:**	**7,262,269,856**
(5)	**Additional SRP Funding Needed per kWh:**	**-$0.00001**
(6)	**Proposed Energy Efficiency Program charge in EEPP**	**$0.01141**
(7)	**Proposed Total Energy Efficiency Program charge in EEPP**	**$0.01140**
(8)	**Proposed Total Energy Efficiency Program charge w/ Uncollectible Recovery**	**$0.01155**

Notes
(1) Projected Budget includes only additional funds for SRP. It does not include costs associated with focused energy efficiency.
(2) Proposed Total Energy Efficiency Program charge is the sum of the "Additional SRP Funding Needed per kWh" and "Proposed Energy Efficiency Program charge in EEPP" lines.
(3) All dollar amounts shown are in $current year.

Item 2 in Table S-1, the Projected Year-End Fund Balance and Interest, is relatively large compared to prior years because of two main reasons:

- An error was identified in the funding forecast calculation spreadsheet for SRP, such that prior year balances were not referenced correctly for year-to-year contiguous calculation. This error was rectified so that year-end fund balances are now accounted for.
- SRP has not yet implemented the LCBS Project, and has therefore not used the funds allocated for the LCBS Project.

15. 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

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By its Attorney, Date
Raquel J. Webster

16. Appendices

Appendix 1
Rhode Island and Company Electric Service Projected Load Growth Rates

Appendix 2
Tiverton NWA Pilot Benefit-Cost Analysis Tables

Appendix 3
Tiverton NWA Pilot Evaluation Deliverables from Opinion Dynamics Corporation

Appendix 4
Projects Screened for NWA

Appendix 5
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Appendix 8
2018 Market and Engagement Plan

Appendix 9
Tiverton NWA Pilot Benefit-Cost Analysis with the RI Test Applied

Appendix 1 – Rhode Island Company Electric Service Projected Load Growth Rates

RHODE ISLAND PROJECTED GROWTH RATES (Percents)

			Annual Growth Rates (percents)										5-yr avg	10-yr avg
State	**County**	**Town**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**'18 to '22**	**'18 to '27**
RI			-1.0	-0.9	-0.7	-0.4	-0.2	-0.1	0.1	0.3	0.4	0.4	-0.7	-0.2
	Bristol		-1.4	-1.3	-1.0	-0.8	-0.5	-0.4	-0.1	0.1	0.2	0.2	-1.0	-0.5
	Kent		-1.3	-1.2	-1.0	-0.7	-0.5	-0.3	-0.1	0.2	0.3	0.2	-0.9	-0.4
	Newport		-1.2	-1.2	-0.9	-0.6	-0.4	-0.3	0.0	0.2	0.3	0.2	-0.9	-0.4
	Providence		-1.1	-1.0	-0.8	-0.5	-0.3	-0.2	0.1	0.3	0.4	0.3	-0.7	-0.3
	Washington		0.1	0.0	0.2	0.3	0.5	0.5	0.7	0.9	0.9	0.8	0.2	0.5
	Newport	Little Compton	-0.5	-0.5	-0.3	-0.1	0.0	0.1	0.3	0.5	0.6	0.5	-0.3	0.1
	Newport	Tiverton	-0.1	-0.2	0.0	0.2	0.3	0.4	0.6	0.7	0.8	0.7	0.0	0.3

vintage: fall 2017

RHODE ISLAND

2018 Electric Peak (MW) Forecast

Long-Term: 2018 to 2032

[Narragansett Electric Company]

January 2018

Rev. 1, 01/10//2018

Advanced Data & Analytics
Business Processes

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Rev. 1	01/10/2018	- add winter peak forecasts
Rev. 0	12/31/2017	- ORIGINAL

General Notes:

- Input data through **August 2017**; Projections from 2018 forward;
- Economic data is from Moody's vintage **August 2017**.
- Energy Efficiency data is vintage **August 2017.**
- Distributed Generation data is vintage **August 2017.**
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (1/2003 to 6/2017); internal unreconciled **preliminary** data (7/2017 to 8/2017).
- Peak load data is metered zone load.
- Peak day & times in this report refer to those for the Company and not for ISO-NE peak.
- The term "Weather-Normal" and "Extreme" 90/10 ("1 in 10") and 95/5 ("1 in 20") weather are based on 20 year average.
- Narragansett Electric Company (NECO) is now shown individually (previous versions had NECO included in the same report as the Massachusetts jurisdiction Companies).
- The modeling process now employs a "reconstructed" for DERs historical data set for input

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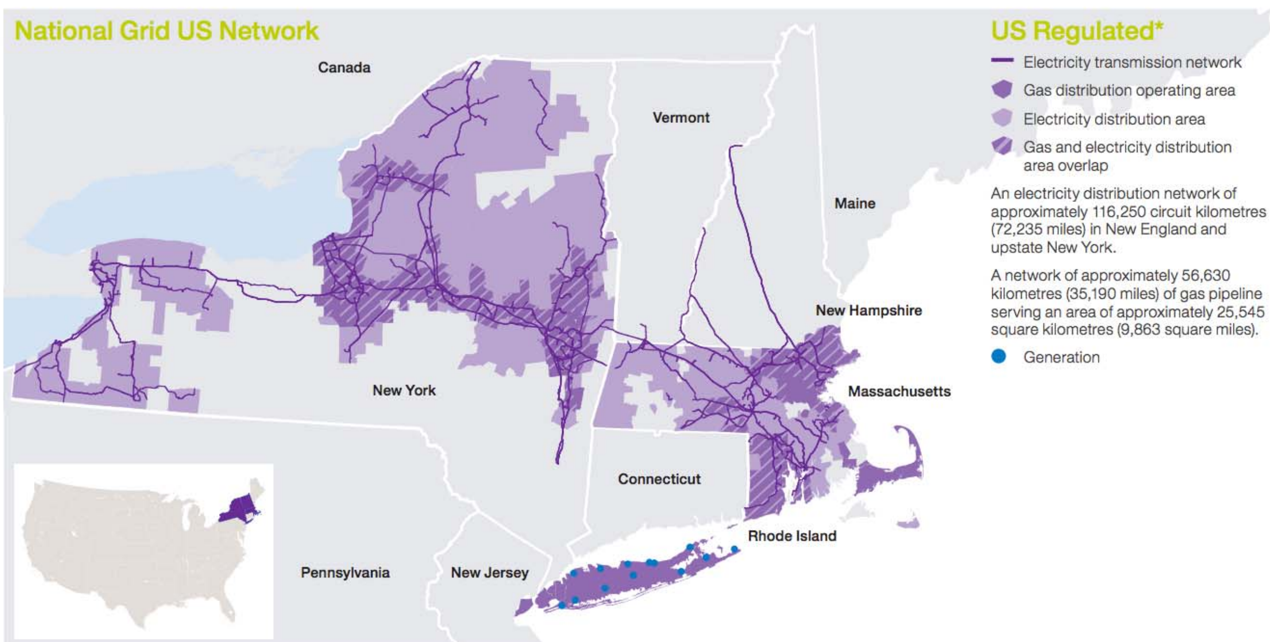
CONTENTS

Summary

National Grid's US electric system is comprised of four companies serving 3.4 million customers in Massachusetts, Rhode Island and Upstate New York. The four electric distribution companies are Massachusetts Electric Company and Nantucket Electric Company, serving 1.3 million customers in Massachusetts, Narragansett Electric Company, serving 0.5 million customers Rhode Island 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 electrical 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 2017 was 1,688[2], on Thursday, July 20th at hour-ending 16. The 2017 peak was 15% below the NECO all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

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

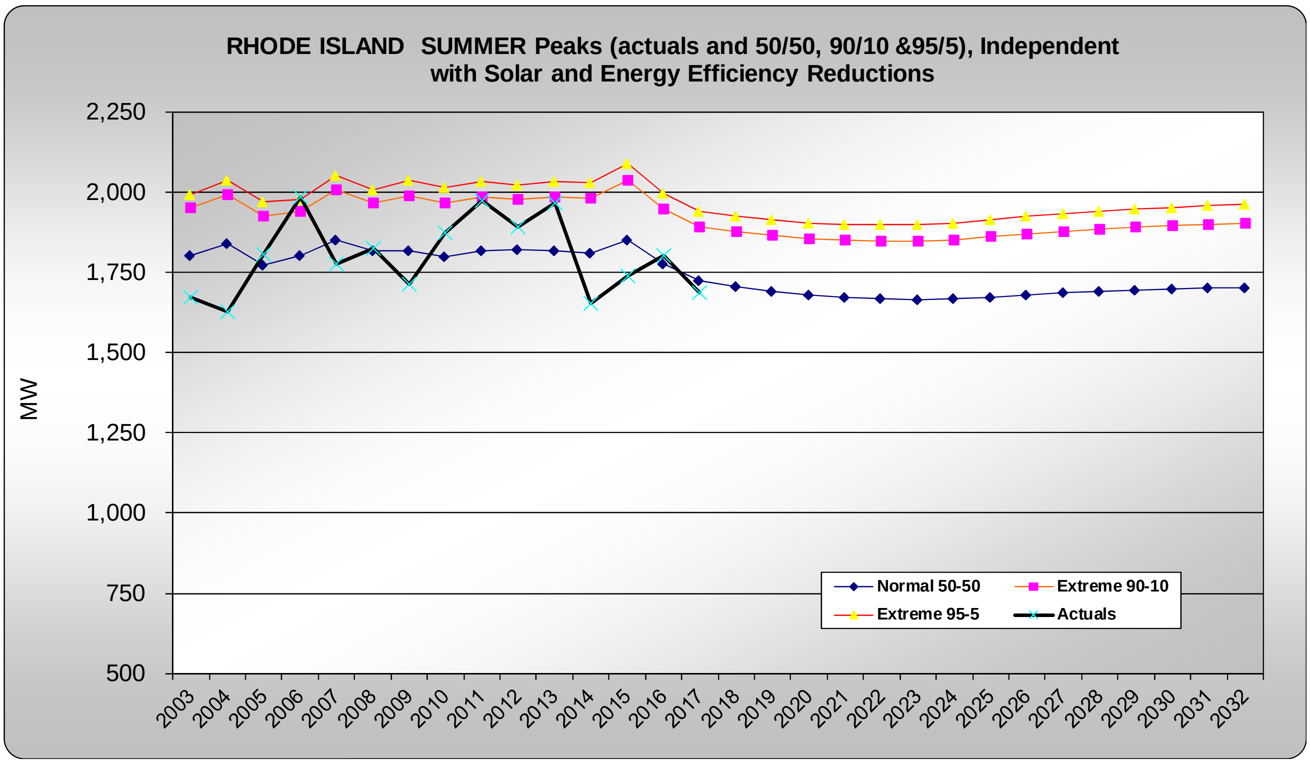
[2] Meter Data Service's system level PRELIMINARY peak and subject to change

This summer's peak weather was considered *__cooler__* than normal (average). This year's peak is estimated to be 35 MW below 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 1,723 MW, a decrease of -3.1% vs. last year's weather-adjusted 'normal' peak.

The forecast indicates that the overall service territory will experience negative growth of -0.1% annually over the next fifteen years, primarily due to the impacts of energy efficiency and solar PV offsetting any underlying economic growth.

Figure 1 shows this forecast graphically.

__Figure 1__



__Forecast Methodology__

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

The overall approach to the peak forecast is to relate (or regress) peak MWs to energy growth. For each zone, peak MWs are regressed against energy growth and company/zonal economic factors (if appropriate). This method allows the peak MW forecasts to grow along with energy growth rates for the Company, however it also allows the peak to adjust to other economic influences in each area.

Each of these models is developed based on a “reconstructed” model of past load. That is, claimed energy efficiency and known solar PV are first added back to the historical data set before the models are 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 and solar-PV are taken out to arrive at the final forecast.

Post-model reductions were made to the initial forecast models for energy efficiency (EE) and solar (DG) 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)

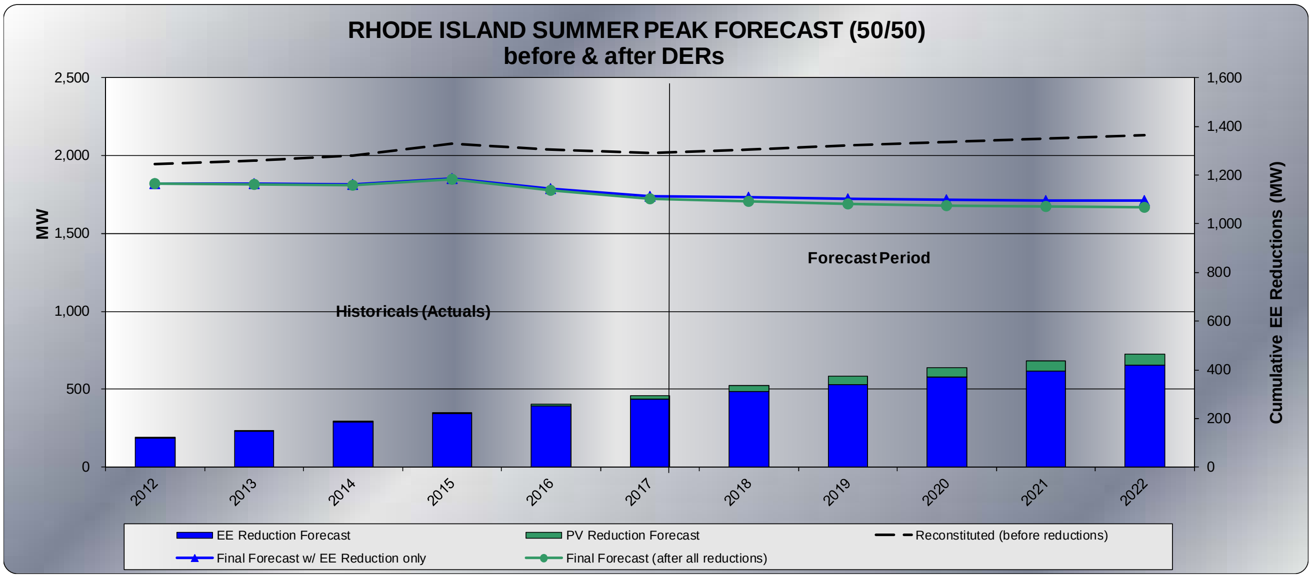
In New England there are a number of policies, programs and technologies that are impacting customer loads. These include, but are not limited to energy efficiency, distributed generation (specifically solar distributed generation) and demand response. These collectively are termed distributed energy 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 (actually the company’s prorata share of EE by load within each ISO zone) for these longer term projections. The ISO-NE EE projections account for state policies, company programs and other market factors.

Figure 2 shows the expected loads and energy efficiency program reductions to NECO peaks by year. As of 2017, it is estimated that these EE programs have reduced loads by 279 MW than if there were no programs run. By 2032, it is expected that this reduction will grow to 582 MW or 25% of what load would have been had these programs not been implemented. Over the fifteen year planning horizon these reductions lower annual growth from 1.0% to 0.1% per year.

Figure 2



Distributed Generation (Solar – PV)

There has been a rapid increase in the adoption of solar[3] 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[4]. 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 three 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 2 above shows the expected NECO loads and solar reductions to peaks by year. As of 2017, it is estimated that this technology may have already reduced system peak loads by 16 MW. By 2032 it is expected that these reductions may grow to 66 MW[5], or about 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 0.1% to -0.1% per year.

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[3] 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.
[4] 2017 Capacity, Energy, Load & Transmission Report, a report by the New England Independent System Operator, Inc., "CELT", dated May 2017.
[5] These are Company system summer peak impacts; these are approximately 21% of connected PV MWs.

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

Explicit reductions to system peaks have been made for these energy efficiency and solar PV programs.

Demand Response

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

Table 2

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.

Weather Assumptions

Weather data is collected from Providence, the relevant weather station for Rhode Island.

The weather variables used in the model include heating degree days for the colder winter months and temperature – humidity indexes (THIs)[6] for the warmer summer months. These weather variables are correlated to the actual days that each peak occurs in each season

[6] 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.

over the historical period. Summer THI uses a weighted three day index (WTHI)[7] 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.

[7] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior

APPENDIX A: NARRAGASETT ELECTRIC COMPANY (NECO)

RHODE ISLAND
SUMMER (Independent) Peaks — **AFTER Solar & Energy Efficiency Reductions**

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2003	1,670		1,803		1,950		1,991		80.1
2004	1,628	-2.5%	1,839	2.0%	1,993	2.2%	2,036	2.3%	78.5
2005	1,805	10.8%	1,772	-3.6%	1,925	-3.4%	1,968	-3.4%	83.1
2006	1,985	10.0%	1,803	1.8%	1,941	0.8%	1,979	0.5%	85.9
2007	1,777	-10.5%	1,852	2.7%	2,006	3.4%	2,050	3.6%	80.9
2008	1,824	2.6%	1,817	-1.9%	1,964	-2.1%	2,006	-2.1%	82.9
2009	1,713	-6.1%	1,816	0.0%	1,988	1.2%	2,036	1.5%	80.3
2010	1,872	9.3%	1,798	-1.0%	1,968	-1.0%	2,016	-1.0%	84.5
2011	1,974	5.5%	1,817	1.1%	1,985	0.9%	2,033	0.8%	84.8
2012	1,892	-4.2%	1,822	0.3%	1,977	-0.4%	2,021	-0.6%	83.5
2013	1,965	3.9%	1,817	-0.3%	1,985	0.4%	2,032	0.6%	84.7
2014	1,653	-15.9%	1,811	-0.4%	1,980	-0.2%	2,028	-0.2%	80.4
2015	1,738	5.1%	1,850	2.2%	2,035	2.8%	2,087	2.9%	80.4
2016	1,803	3.8%	1,778	-3.9%	1,946	-4.4%	1,994	-4.5%	82.6
2017	1,688	-6.4%	1,723	-3.1%	1,893	-2.8%	1,941	-2.7%	81.7
2018	-	-	1,706	-1.0%	1,878	-0.8%	1,926	-0.7%	-
2019	-	-	1,691	-0.9%	1,864	-0.7%	1,913	-0.7%	-
2020	-	-	1,679	-0.7%	1,855	-0.5%	1,905	-0.5%	-
2021	-	-	1,672	-0.4%	1,849	-0.3%	1,900	-0.2%	-
2022	-	-	1,668	-0.2%	1,847	-0.1%	1,899	-0.1%	-
2023	-	-	1,666	-0.1%	1,848	0.0%	1,899	0.0%	-
2024	-	-	1,668	0.1%	1,852	0.2%	1,904	0.3%	-
2025	-	-	1,673	0.3%	1,860	0.4%	1,913	0.5%	-
2026	-	-	1,681	0.4%	1,870	0.5%	1,923	0.5%	-
2027	-	-	1,687	0.4%	1,878	0.4%	1,932	0.5%	-
2028	-	-	1,692	0.3%	1,885	0.4%	1,940	0.4%	-
2029	-	-	1,696	0.2%	1,891	0.3%	1,947	0.3%	-
2030	-	-	1,699	0.2%	1,897	0.3%	1,953	0.3%	-
2031	-	-	1,702	0.1%	1,901	0.2%	1,958	0.2%	-
2032	-	-	1,703	0.1%	1,904	0.2%	1,962	0.2%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Compound Avg. 10 yr ('07 to '17)	-0.7%	-0.6%	-0.5%
Compound Avg. 5 yr ('12 to '17)	-1.1%	-0.9%	-0.8%
Compound Avg. 5 yr ('17 to '22)	-0.7%	-0.5%	-0.4%
Compound Avg. 10 yr ('17 to '27)	-0.2%	-0.1%	0.0%
Compound Avg. 15 yr ('17 to '321)	-0.1%	0.0%	0.1%

WTHI

NORMAL	82.2
EXTREME 90/10	85.0
EXTREME 95/5	85.8

RHODE ISLAND SUMMER Independent 50/50 Peaks (MW) (before & after DERs)

Calendar Year	SYSTEM PEAK (50/50) Reconstituted (before reductions)	Final Forecast w/ EE Reduction only	Final Forecast (after all reductions)	DER REDUCTIONS EE Reduction Forecast	PV Reduction Forecast	EE % of 'Reconstituted' Deliveries	PV % of 'Reconstituted' Deliveries
2003	1,813	1,803	**1,803**	9	0	0.5%	0.0%
2004	1,860	1,839	**1,839**	21	0	1.1%	0.0%
2005	1,802	1,772	**1,772**	30	0	1.7%	0.0%
2006	1,844	1,803	**1,803**	41	0	2.2%	0.0%
2007	1,902	1,852	**1,852**	51	0	2.7%	0.0%
2008	1,878	1,817	**1,817**	61	0	3.3%	0.0%
2009	1,893	1,816	**1,816**	77	0	4.0%	0.0%
2010	1,887	1,798	**1,798**	89	0	4.7%	0.0%
2011	1,919	1,818	**1,817**	102	0	5.3%	0.0%
2012	1,944	1,823	**1,822**	121	0	6.2%	0.0%
2013	1,968	1,820	**1,817**	148	2	7.5%	0.1%
2014	2,001	1,814	**1,811**	187	4	9.3%	0.2%
2015	2,075	1,855	**1,850**	220	5	10.6%	0.2%
2016	2,036	1,785	**1,778**	250	7	12.3%	0.4%
2017	2,018	1,739	**1,723**	279	16	13.8%	0.8%
2018	2,041	1,731	**1,706**	310	25	15.2%	1.2%
2019	2,063	1,723	**1,691**	340	32	16.5%	1.6%
2020	2,087	1,718	**1,679**	369	39	17.7%	1.9%
2021	2,109	1,714	**1,672**	395	42	18.7%	2.0%
2022	2,131	1,712	**1,668**	419	44	19.7%	2.1%
2023	2,153	1,712	**1,666**	441	47	20.5%	2.2%
2024	2,177	1,717	**1,668**	460	49	21.1%	2.3%
2025	2,202	1,725	**1,673**	477	51	21.7%	2.3%
2026	2,226	1,734	**1,681**	492	53	22.1%	2.4%
2027	2,249	1,742	**1,687**	507	56	22.5%	2.5%
2028	2,272	1,750	**1,692**	522	58	23.0%	2.5%
2029	2,293	1,756	**1,696**	537	60	23.4%	2.6%
2030	2,314	1,761	**1,699**	552	62	23.9%	2.7%
2031	2,333	1,766	**1,702**	567	64	24.3%	2.8%
2032	2,352	1,770	**1,703**	582	66	24.8%	2.8%

'07 to '17: 10-year avg	0.6%	-0.6%	**-0.7%**
'12 to '17: 5-year avg.	0.8%	-0.9%	**-1.1%**
'17 to '22: 5-year avg.	1.1%	-0.3%	**-0.7%**
'17 to '27: 10-year avg	1.1%	0.0%	**-0.2%**
'17 to '32: 15-year avg	1.0%	0.1%	**-0.1%**

NECO
WINTER (Independent) Peaks

AFTER Energy Efficiency Reductions

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		1,303		1,369		1,388		56.0
2004	1,394	0.4%	1,427	9.5%	1,487	8.6%	1,504	8.3%	37.7
2005	1,329	-4.6%	1,317	-7.7%	1,373	-7.6%	1,389	-7.6%	45.5
2006	1,329	0.0%	1,308	-0.6%	1,366	-0.5%	1,383	-0.5%	46.3
2007	1,352	1.7%	1,313	0.4%	1,374	0.6%	1,392	0.7%	46.6
2008	1,305	-3.5%	1,313	0.0%	1,386	0.8%	1,406	1.0%	41.2
2009	1,294	-0.8%	1,332	1.4%	1,404	1.3%	1,425	1.3%	35.9
2010	1,315	1.6%	1,238	-7.0%	1,316	-6.3%	1,338	-6.1%	53.1
2011	1,243	-5.5%	1,248	0.8%	1,326	0.7%	1,347	0.7%	42.1
2012	1,320	6.2%	1,277	2.3%	1,341	1.2%	1,359	0.9%	51.9
2013	1,328	0.7%	1,315	3.0%	1,381	3.0%	1,399	3.0%	44.7
2014	1,275	-4.0%	1,210	-8.0%	1,279	-7.4%	1,298	-7.2%	52.7
2015	1,223	-4.1%	1,188	-1.8%	1,251	-2.2%	1,269	-2.3%	53.7
2016	1,239	1.3%	1,273	7.1%	1,340	7.1%	1,359	7.1%	37.0
2017	-		1,156	-9.2%	1,220	-9.0%	1,238	-8.9%	-
2018	-		1,141	-1.3%	1,205	-1.2%	1,223	-1.2%	-
2019	-		1,131	-0.8%	1,196	-0.7%	1,215	-0.7%	-
2020	-		1,123	-0.7%	1,189	-0.6%	1,207	-0.6%	-
2021	-		1,110	-1.2%	1,176	-1.1%	1,195	-1.0%	-
2022	-		1,102	-0.7%	1,169	-0.6%	1,188	-0.6%	-
2023	-		1,096	-0.6%	1,163	-0.5%	1,183	-0.4%	-
2024	-		1,093	-0.2%	1,162	-0.2%	1,181	-0.1%	-
2025	-		1,092	-0.1%	1,161	-0.1%	1,180	-0.1%	-
2026	-		1,091	-0.1%	1,160	0.0%	1,180	0.0%	-
2027	-		1,093	0.2%	1,163	0.2%	1,183	0.2%	-
2028	-		1,096	0.3%	1,167	0.4%	1,187	0.4%	-
2029	-		1,095	-0.2%	1,166	-0.1%	1,186	-0.1%	-
2030	-		1,094	0.0%	1,166	0.0%	1,187	0.0%	-
2031	-		1,093	-0.1%	1,166	0.0%	1,186	0.0%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Compound Avg. 10 yr ('06 to '16)	-0.3%	-0.2%	-0.2%
Compound Avg. 5 yr ('11 to '16)	0.4%	0.2%	0.2%
Compound Avg. 5 yr ('16 to '21)	-2.7%	-2.6%	-2.5%
Compound Avg. 10 yr ('16 to '26)	-1.5%	-1.4%	-1.4%
Compound Avg. 15 yr ('16 to '31)	-1.0%	-0.9%	-0.9%

HDD_wtd

NORMAL	43.1
EXTREME 90/10	53.2
EXTREME 95/5	56.1

Appendix B: POWER SUPPLY AREAS (PSAs)

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

			2017 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**	**2018**	**2019**	**2020**	**2021**	**2022**	**'18 to '22**	**'23 to '27**	**'28 to '32**
RI	Blackstone Valley	RI	102.1%	112.1%	114.9%	-1.0	-0.9	-0.7	-0.4	-0.2	-0.7	0.2	0.2
RI	Newport	RI	102.1%	112.1%	114.9%	-1.2	-1.1	-0.9	-0.6	-0.4	-0.8	0.1	0.1
RI	Providence	RI	102.1%	112.1%	114.9%	-1.1	-1.0	-0.8	-0.6	-0.3	-0.8	0.1	0.2
RI	Western Narraganset	RI	102.1%	112.1%	114.9%	-0.4	-0.4	-0.2	0.0	0.2	-0.2	0.5	0.4

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current summer 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 summer 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

Appendix 2 – Tiverton NWA Pilot Benefit-Cost Analysis Tables

Table S-2
System Reliability Procurement - Tiverton/Little Compton
Summary of Cost-Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	2018	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$568.0**	**$0.0**	**$5,074.6**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$66.94	$0.0	$3,348.7
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$341.6	$0.0	$1,043.7
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$0.0	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$510.9**	**$90.8**	**$3,617.4**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$281.3	$0.0	$1,664.1
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$229.6	$90.8	$1,953.3
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**1.11**	**-**	**1.40**

Notes:

(1) Focused EE benefits in each year include the NPV (over the life of those measures) of all TRC benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.

(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

(3) DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.

(4) Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.

(5) EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install programs. These are the programs through which measures in this SRP pilot will be offered.

(6) SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers reflect year end projections.

Table S-3
National Grid
System Reliability Procurement - Tiverton/Little Compton
Annual Budgets and Actual Costs
$(000)

	Program Planning & Administration	Marketing	Rebates and Other Customer Incentives	Sales, Technical Assistance & Training	Evaluation & Market Research	Total
2012	$2.6	$24.7	$32.5	$2.0	$25.1	$86.8
2013	$67.9	$77.1	$102.0	$1.4	$90.7	$339.0
2014	$74.9	$78.1	$87.0	$6.0	$125.4	$371.5
2015	$90.6	$85.1	$67.6	$97.6	$157.2	$498.1
2016	$31.5	$89.6	$11.9	$60.0	$136.3	$329.3
2017	$9.5	$76.6	$3.5	$31.0	$109.0	$229.6
2018	$0.0	$0.0	$0.0	$0.0	$90.8	$90.8
Total	**$277.0**	**$431.3**	**$304.4**	**$198.1**	**$643.6**	**$1,854.3**

Notes:
(1) The annual totals in this table represent only the forecasted funds necessary to run the Tiverton/Little Compton pilot. They do not include costs associated with focused energy efficiency or with SRP participant costs.
(2) All amounts shown are in $current year.
(3) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers have been updated to reflect year end projections

Table S-4
System Reliability Procurement - Tiverton/Little Compton
Summary of kW, and kWh New Installs Per Year

			Capacity (kW)			Energy (MWh)	
			Summer	Winter	Lifetime	Maximum Annual	Lifetime
2012	EE	Residential	17	20	102	121	642
		Commercial	4	2	44	7	85
		SRP	8	8	121	4	55
	Non-EE	Demand Response	13	0	13		
		Total	**42**	**30**	**280**	**132**	**782**
2013	EE	Residential	77	86	527	505	2,953
		Commercial	55	32	653	205	2,440
		SRP	78	33	1,362	80	883
	Non-EE	Demand Response	56	0	56		
		Total	**266**	**152**	**2,598**	**790**	**6,276**
2014	EE	Residential	50	59	419	334	2,737
		Commercial	12	9	128	69	758
		SRP	40	9	746	51	535
	Non-EE	Demand Response	17	0	17		
		Total	**120**	**78**	**1,310**	**455**	**4,030**
2015	EE	Residential	93	109	850	619	5,454
		Commercial	17	15	207	41	489
		SRP	23	7	396	26	271
	Non-EE	Demand Response	11	0	11		
		Total	**144**	**131**	**1,465**	**685**	**6,214**
2016	EE	Residential	50	58	464	318	2,807
		Commercial	5	4	61	29	359
		SRP	29	4	255	21	183
	Non-EE	Demand Response	6	0	6		
		Total	**90**	**67**	**786**	**368**	**3,349**
2017	EE	Residential	38	37	212	242	2,188
		Commercial	0	0	0	0	0
		SRP	22	38	257	200	1,796
	Non-EE	Demand Response	0	0	0		
		RFP	13	0	91	9	61
		Total	**74**	**75**	**560**	**450**	**4,045**
Grand Total			**735**	**532**	**7,000**	**2,880**	**24,696**

Notes:
(1) The "EE" savings include both Focused Energy Efficiency savings and SRP Energy Efficiency Savings.
(2) Measures unique to SRP and not offered in the same way through the statewide EE programs are listed as a separate line item (SRP) under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) Savings in this table are not cumulative. Each year shows savings from measures that will have been installed within that year.
(4) 2012-2017 numbers have been updated to reflect year end data.
(5) Demand Response estimated kWh savings are shown on table S-6.

Table S-5
System Reliability Procurement - Tiverton/Little Compton
Summary of Incremental Benefits By Year

			Capacity ($)						Energy ($)					Non-Electric ($)	
			Total Benefits	**Summer Generation**	**Winter Generation**	**Transmission**	**MDC/ Deferral(3)**	**DRIPE**	**Winter Peak**	**Winter Off-Peak**	**Summer Peak**	**Summer Off-Peak**	**DRIPE**	**Resource**	**Non - Resource**
2012	**EE**	Residential	68,954	2,735	0	2,314	9,724	473	17,057	8,696	10,374	4,444	5,586	0	7,552
		Commercial	21,251	1,709	0	984	4,135	474	2,831	688	1,698	338	627	0	7,765
		SRP	88,810	6,590	0	2,638	11,082	1,224	35	117	2,257	1,193	292	63,381	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**179,015**	**11,035**	**0**	**5,936**	**24,941**	**2,171**	**19,924**	**9,500**	**14,329**	**5,975**	**6,505**	**63,381**	**15,317**
2013	**EE**	Residential	715,520	19,112	0	12,066	50,700	3,990	79,472	43,584	49,862	22,710	25,456	362,998	45,569
		Commercial	299,547	31,822	0	14,689	61,719	8,065	84,675	20,430	50,364	10,075	17,708	0	0
		SRP	310,370	67,287	0	30,582	128,499	14,693	261	967	45,399	16,336	6,346	0	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**1,325,438**	**118,221**	**0**	**57,338**	**240,918**	**26,749**	**164,407**	**64,981**	**145,625**	**49,122**	**49,510**	**362,998**	**45,569**
2014	**EE**	Residential	641,519	29,866	0	17,044	0	3,214	68,295	46,885	41,650	17,727	35,790	350,408	30,639
		Commercial	75,220	11,229	0	5,201	0	963	26,032	6,580	12,466	2,916	9,835	0	0
		SRP	136,801	63,099	0	30,271	0	5,344	118	479	22,591	8,861	6,038	0	0
	Non-EE	Demand Reduction	5,563	1,989	0	3,521	0	0	0	0	54	0	0	0	0
		Deferral	174,188	0	0	0	174,188	0	0	0	0	0	0	0	0
		Total	**1,033,291**	**106,183**	**0**	**56,037**	**174,188**	**9,521**	**94,445**	**53,944**	**76,760**	**29,504**	**51,662**	**350,408**	**30,639**
2015	**EE**	Residential	953,990	74,891	0	34,529	0	7,247	153,698	83,936	75,394	38,919	72,456	366,076	46,844
		Commercial	70,792	21,238	0	8,337	0	1,422	18,325	4,693	9,039	2,126	5,611	0	0
		SRP	77,987	38,200	0	15,987	0	2,917	73	292	12,461	5,051	3,006	0	0
	Non-EE	Demand Reduction	6,802	2,411	0	4,074	0	0	0	0	317	0	0	0	0
		Deferral	171,482	0	0	0	171,482	0	0	0	0	0	0	0	0
		Total	**1,281,053**	**136,739**	**0**	**62,929**	**171,482**	**11,587**	**172,095**	**88,920**	**97,211**	**46,096**	**81,074**	**366,076**	**46,844**
2016	**EE**	Residential	399,334	65,614	0	5,410	0	0	82,277	50,023	37,105	20,112	1,543	115,983	21,267
		Commercial	35,633	9,151	0	702	0	0	14,076	3,648	6,434	1,454	168	0	0
		SRP	88,093	35,504	0	2,979	0	0	603	1,102	6,683	3,067	179	37,976	0
	Non-EE	Demand Reduction	5,260	3,604	0	1,224	0	0	0	0	431	0	0	0	0
		Deferral	159,412	0	0	0	159,412	0	0	0	0	0	0	0	0
		Total	**687,732**	**113,873**	**0**	**10,315**	**159,412**	**0**	**96,957**	**54,772**	**50,654**	**24,633**	**1,889**	**153,959**	**21,267**
2017	**EE**	Residential	386,311	45,043	0	3,371	0	0	66,000	36,872	31,049	16,835	664	161,410	25,067
		Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
		SRP	358,713	40,403	0	3,035	0	0	57,016	29,961	28,040	13,190	591	161,410	25,067
	Non-EE	Demand Reduction	11,320	9,853	0	1,106	0	0	0	0	362	0	0	0	0
		Deferral	148,191	0	0	0	148,191	0	0	0	0	0	0	0	0
		Total	**904,536**	**95,299**	**0**	**7,512**	**148,191**	**0**	**123,016**	**66,833**	**59,451**	**30,026**	**1,255**	**322,820**	**50,133**
Grand Total			**5,411,064**	**581,351**	**0**	**200,066**	**919,132**	**50,028**	**670,844**	**338,950**	**444,030**	**185,356**	**191,895**	**1,619,643**	**209,769**

Notes:
(1) The "EE" benefits include both Focused Energy Efficiency benefits and SRP Energy Efficiency benefits.
(2) Measures unique to SRP are listed as a separate line item under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) The MDC/Deferral column represents: 2012-2013: the system-average distribution benefit and 2014-2017: the calculated deferral benefit as defined in the notes section of Table S-2
(4) All benefits are in $current year except deferral benefits which are in $2014.
(5) 2012-2017 numbers have been updated to reflect year end data.
(6) Benefits due to EE reflect new installations within the year. Benefits due to Non-EE reflect cumulative installations

Table S-6
System Reliability Procurement - Tiverton/Little Compton
Demand Reduction

	Tstats	Smart Plug
Per- Event Capacity Savings per Residential Participant (kW)	**0.49**	**0.04**
Per- Event Capacity Savings per C&I Participant (kW)	**0.98**	**n/a**

	2012	2013	2014	2015	2016	2017
Number of Event Hours						
Thermostats			12	60	72	60
Plug Load Devices			6	30	36	0
Units						
Thermostats - Residential	35	167	205	232	247	247
Thermostats - C&I	0	4	4	4	4	4
Plug Load Devices	0	145	249	298	308	308
Forecasted Annual Capacity Savings (kW)	**13**	**69**	**86**	**97**	**103**	**103**
Thermostats - Residential	13	61	75	85	91	91
Thermostats - C&I	0	3	3	3	3	3
Smart Plugs	0	4	7	9	9	9
Forecasted Annual Energy Savings (kWh)	**0**	**0**	**984**	**5,560**	**7,080**	**5,623**
Thermostats - Residential	0	0	904	5,116	6,536	5,446
Thermostats - C&I	0	0	35	176	212	176
Smart Plugs	0	0	45	268	333	0
Cumulative Annual Demand Reduction Benefits ($)			**5,563**	**6,802**	**5,260**	**11,320**
Annual Energy Benefits ($)			54	317	431	362
Annual Capacity Benefits ($)			5,510	6,485	4,828	10,958

Notes:
(1) Forecasted event hours are based on an assumed three days of four-hour events, four times per year. In each event, it is assumed that the demand reduction will be staggered in two groups and cycled on and off.
(2) Savings above represent 75% of max to account for non-participation.
(2) All dollar amounts are in $current year.
(3) 2012-2017 numbers have been updated to reflect year end data.

Table S-7
System Reliability Procurement - Tiverton/Little Compton
Potential for Wires Project Deferral at Year Begin

	2012	2013	2014	2015	2016	2017	2018
Cumulative Annual kW from Energy Efficiency			**239**	**342**	**475**	**559**	**619**
Focused Energy Efficiency			153	215	325	381	419
SRP Energy Efficiency			86	127	149	178	200
Cumulative Annual kW from Demand Reduction			**82**	**86**	**97**	**103**	**103**
Thermostats - Residential			74	75	85	91	91
Thermostats - C&I			3	3	3	3	3
Smart Plugs			4	7	9	9	9
Cumulative Annual kW from RFP							**13**
Total Cumulative kW Reduction From DemandLink			**321**	**427**	**572**	**662**	**735**
Total Cumulative kW Reduction Needed to Defer Wires Project			**150**	**390**	**630**	**860**	**1,000**
% Deferral Targets Achieved by DemandLink			214%	110%	91%	77%	74%

Notes:
(1) All kW amounts are Summer kW and are cumulative.
(2) This table shows the number of kW have been either installed through EE or have become available to reduce through demand reduction by the end of the previous year to therefore contribute to the deferral of the wires investment in the current year.
(3) kW in Reserve acts as insurance against customers overriding the demand reduction themselves, so that the required reduction is still met.
(4) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers have been updated to reflect year end projections.

Appendix 3 –Tiverton NWA Pilot Evaluation Deliverables from Opinion Dynamics Corporation

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National Grid Rhode Island System Reliability Procurement Pilot: 2012-2017 Summary Report

July 25, 2018

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Opinion Dynamics

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Executive Summary

Feeders 33 and 34 of the Tiverton substation serve approximately 4,200 residential and 1,000 commercial customers in the coastal Rhode Island communities of Tiverton and Little Compton. In 2010, National Grid forecasted that these feeders would be capacity-constrained during summer afternoon peak hours starting in 2014. Weighing the cost of substation upgrades against non-wires alternatives, National Grid designed the System Reliability Procurement (SRP) pilot with a goal of reducing summer peak demand by up to 1 MW by 2017, thus deferring substation upgrades to at least 2018. Plans for the SRP non-wires alternative were filed and approved in 2012. After five years of activity, National Grid ended the SRP pilot in late 2017.

This report presents a summary of key findings from annual evaluations of the Rhode Island System Reliability Procurement (SRP) Pilot (2012-2017), conducted by Opinion Dynamics Corporation under contract to National Grid, and a final assessment of whether the pilot met its goal of delivering 1 MW in summer peak demand reduction to defer the substation update to 2018.

Program Offerings

National Grid used a three-pronged strategy to pursue its SRP peak demand reduction goals: (1) implementation of the DemandLink Programmable Controllable Thermostat Program, a new SRP-specific demand response offering, (2) enhancement of existing statewide energy efficiency offerings, and (3) introduction of new SRP-specific energy efficiency offerings. All three components were supported by an intensive and targeted marketing and outreach campaign that began in March 2012.

- **DemandLink Thermostat Program.** The DemandLink Thermostat Program provided temperature control devices to pilot-area customers. All participants received a WiFi-enabled programmable thermostat. Customers with window air conditioning (window AC) also received one or more plug devices, which allowed the WiFi-enabled thermostat to control their window AC unit(s). To be eligible, customers had to have a WiFi internet connection and either central air conditioning (central AC) or window AC, and they had to agree to participate in demand optimization events for at least two years. National Grid began calling demand response events in July 2014.

- **Enhanced Statewide Energy Efficiency Offerings.** National Grid provided increased incentives and conducted targeted customer outreach for three existing statewide energy efficiency offerings:

  - The **EnergyWise Home Energy Assessment Program** provides residential customers with a home energy assessment and a range of direct install measures. Beginning in 2014, the program offered pilot area customers LEDs instead of CFLs.

  - The **Small Business Direct Install (SBDI) Program** is the commercial equivalent of the EnergyWise Program, targeting small non-residential customers.

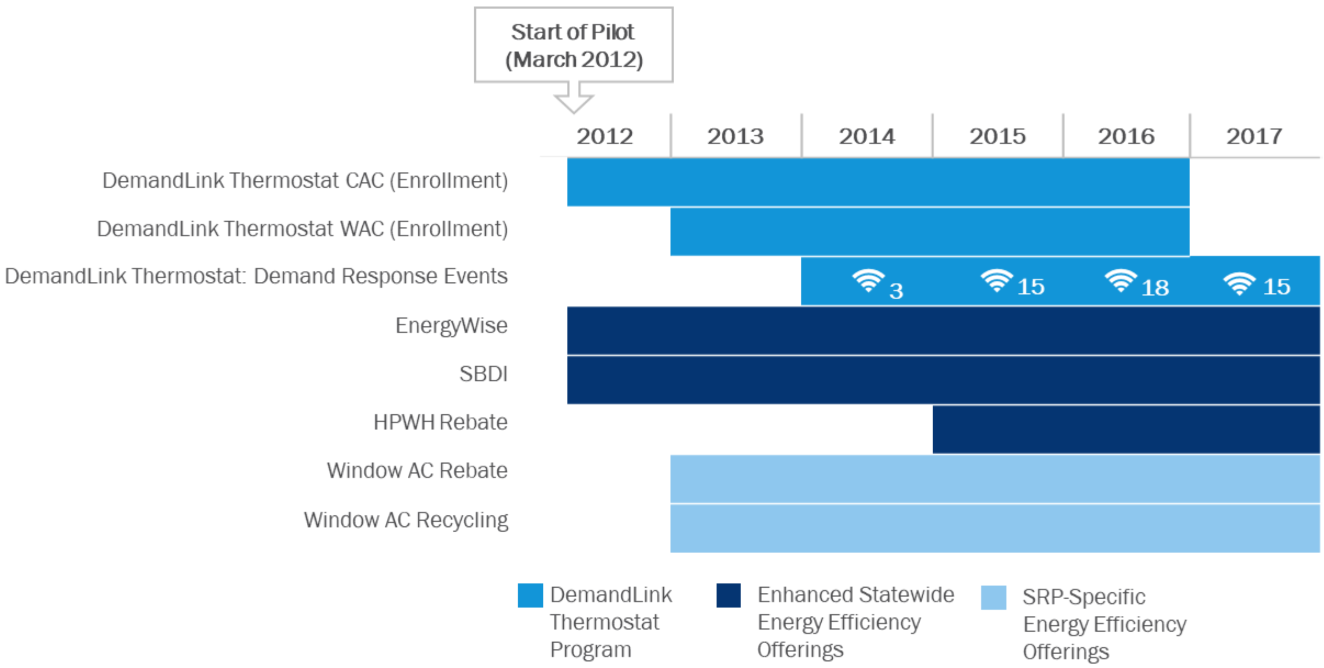
  - In 2015, National Grid began offering customers an enhanced rebate for the purchase of a new electric **heat pump water heaters (HPWH)**. To be eligible for the rebate, customers had to participate in the DemandLink Thermostat Program.

- **SRP-Specific Energy Efficiency Offerings.** To capitalize on the high incidence of window AC in the pilot area, National Grid introduced two new SRP-specific window AC rebate opportunities in 2013. Both rebates were available each year between May 1st and November 1st:

- **DemandLink Window AC Rebate Program.** Customers in Tiverton and Little Compton could receive a $50 rebate for the purchase of qualifying new window AC units, up to four units per household. Eligible units included those with an energy efficiency ratio (EER) greater than or equal to 10.8.
- **DemandLink Window AC Recycling Program.** Customers in Tiverton and Little Compton could receive a $25 rebate for window AC units they recycled, up to four units per household.

Figure ES-1 summarizes the timeline of the various program offerings.

Figure ES-1. Timeline of Program Offerings



Evaluation Activities

National Grid Rhode Island contracted with Opinion Dynamics to conduct annual evaluations of the SRP pilot. Throughout the pilot, evaluation activities were focused on two main topics: (1) the effectiveness of marketing activities in promoting and increasing program participation and (2) the load impacts realized by the pilot. In addition, some of the evaluations covered process-related topics such as drivers of and barriers to participation and participant experience during demand response events.

In support of the annual evaluations, Opinion Dynamics conducted a range of primary data collection activities, including several surveys with EnergyWise and DemandLink participants, two residential leads surveys, a general population survey, a DemandLink event follow-up survey, and a non-participant focus group. Impact analyses included application of deemed savings values to estimate EnergyWise and SBDI load impacts as well as HPWH savings; development of per unit savings estimates for window AC rebates; and estimation of central AC and window AC DR event impacts using regression analysis. Each annual evaluation concluded with an annual evaluation report.

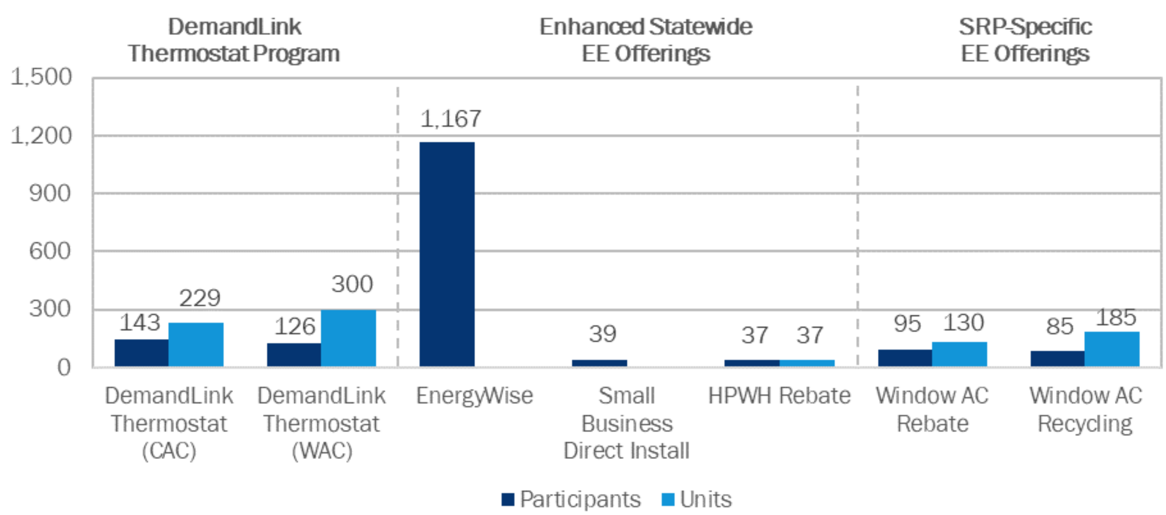
The findings and conclusions presented in this report are drawn from these annual evaluations. The objective of this summary report is to provide a big picture synthesis of the pilot's efforts, including what worked well and what did not work well, as well as lessons learned for potential future pilots. This report therefore does not repeat detailed findings from the earlier evaluation reports. However, where helpful, we include supporting information in the appendices and provide references to the earlier evaluation reports.[1]

Participation and Impact Summary

Overall, participation in the SRP pilot fell short of expectations, and cumulative load impacts did not meet the 1 MW goal. While the pilot succeeded in increasing enrollment in the EnergyWise Program and, to a lesser extent the SBDI Program, participation in the other program offerings was modest. In particular, participation in and savings from the DemandLink Thermostat Program fell short of expectations, largely driven by the low incidence of central AC among pilot area residents, challenges with thermostat and plug device connectivity, and a conservative event strategy.

Figure ES-2 summarizes pilot period participation in the pilot program components.

Figure ES-2. Pilot Area Participation and Equipment Installations (2012-2017)



Source: Program Tracking Data

We estimate cumulative peak demand savings for the pilot period to be 316 kW, less than a third of the 1 MW goal. Cumulative savings include all installations through the EnergyWise, SBDI, and rebate programs since 2012, excluding measures that have reached the end of their useful life. For the demand response events, impacts are based on participants whose thermostats were operational and able to receive the event signal and control cooling equipment the events.

The EnergyWise and SBDI programs were the biggest contributors to total load impacts, with 152 kW (48% of the total) and 96 kW (31% of the total), respectively. Demand response events accounted for 36 kW (11% of the total). Notably, load impacts from participants with window AC were nearly zero in 2016, leading the

[1] Appendix A presents a summary of the evaluation activities and key deliverables completed for each year of the SRP pilot.

program to stop calling events for these participants. Savings from the HPWH and window AC rebates were relatively small, accounting for a combined 31 kW (10% of the total).

Table ES-1 summarizes the cumulative SRP peak load impacts.

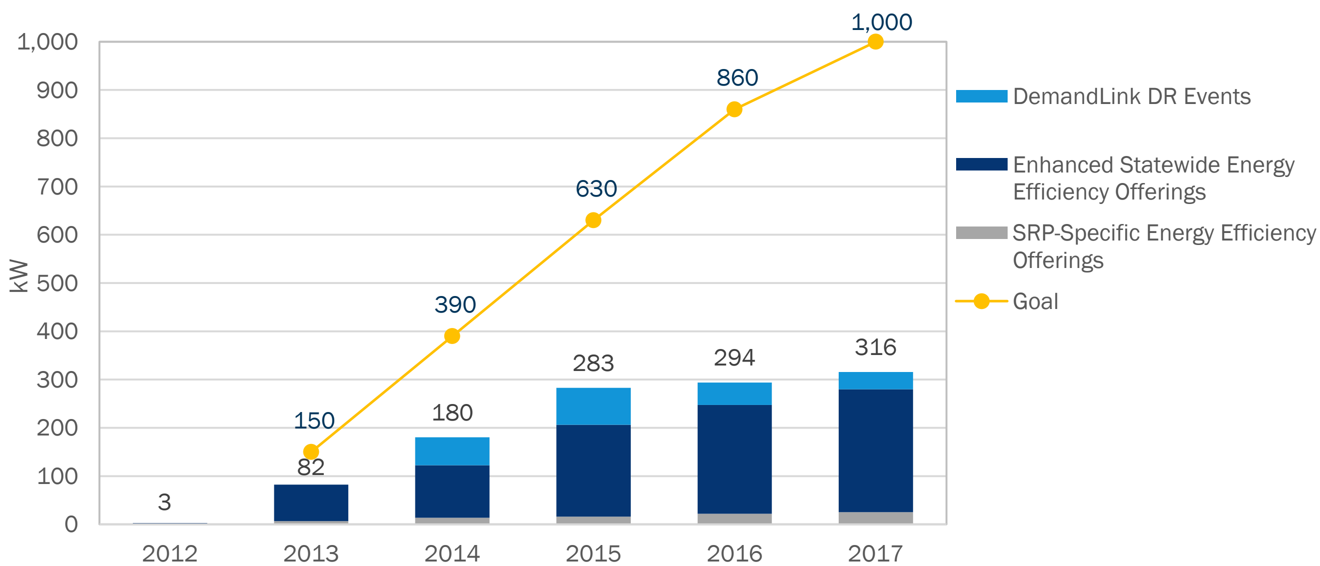
Table ES-1 Cumulative SRP Peak Load Impacts (kW)

Program	2012	2013	2014	2015	2016	2017	% 2017
DemandLink DR Events (CAC)	--	--	56.0	76.0	46.4	35.7	11%
DemandLink DR Events (WAC)	--	--	2.0	0.6	0.02	--	0%
EnergyWise Program	2.7	17.6	41.6	102.4	130.7	152.4	48%
Small Business Program	--	57.9	67.2	86.1	90.6	96.4	31%
Heat Pump Water Heater Rebate	--	--	--	1.6	4.3	5.9	2%
Window AC Purchase Rebate	--	0.8	1.0	1.2	1.5	1.6	1%
Window AC Recycling Rebate	--	6.1	12.6	14.9	20.4	23.6	7%
TOTAL	**2.7**	**82.4**	**180.3**	**282.9**	**293.9**	**315.7**	**100%**

Source: PY2012-2017 Gross Impact Analyses

Figure ES-3 shows the pilot's cumulative load impacts compared to the cumulative reduction National Grid expected to need to defer substation upgrades.

Figure ES-3. Cumulative Load Impacts (kW) Compared to Goal



Source: PY2012-2017 Gross Impact Analyses

Even though the pilot did not meet the 1 MW load reduction goal, its initial progress postponed the investment of the wires alternative that would have occurred in 2014 if not earlier. The investment in the substation upgrade was further deferred due to slower than expected load growth and cooler summer temperatures in 2017. However, since peak demand on feeders 33 and 34 is still high, National Grid decided in 2017 to issue a Request for Proposal (RFP) for a battery storage solution. Battery power will be used to meet the remaining excess demand during peak load times, meaning that substation upgrades can be further deferred.

Key Findings and Recommendations

Based on the annual evaluations of the SRP pilot, we provide the following key findings and recommendations for potential future pilot offerings.

Goal Attainment

- While the pilot did not meet the 1 MW load reduction goal, its initial progress postponed the investment of the wires alternative that would have occurred in 2014 if not earlier. The investment in the substation upgrade was further deferred due to slower than expected load growth and cooler summer temperatures in 2017. Two key factors contributed to the pilot falling short of its goal:
    - **Lower than expected savings from the DemandLink Thermostat Program:** Residential demand response events achieved only 40 kW in 2017, compared to a target of 455 kW.[2] Low incidence of central AC among pilot area residents, challenges with thermostat and plug device connectivity, and a conservative event strategy were largely responsible for the residential shortfalls. In addition, the pilot had a target of 134 kW for commercial demand response events but never rolled out a commercial DemandLink program.
    - **Limited savings from SRP-specific energy efficiency offerings:** National Grid had set an aggressive load reduction target of 685 kW for SRP-specific energy efficiency offerings. However, National Grid only introduced two SRP-specific energy efficiency measures (rebates for new energy efficient window AC units and for window AC recycling), which only achieved a combined 25 kW due to limited uptake.
- Compared to the other two components, impacts from the enhanced statewide energy efficiency offerings (255 kW) were much closer to target (320 kW). These impacts largely resulted from increased participation in the EnergyWise Program. The pilot might have met this target, had it not been for two factors: (1) Lighting measures accounted for the vast majority of the savings in the EnergyWise Program. The changing baseline for residential lighting measures due to new EISA standards means that savings from these measures have been decreasing over time. (2) The pilot deemphasized the commercial sector after an initial push in 2013. As a result, savings from the SBDI Program between 2014 and 2017 were small.
- Because peak demand on feeders 33 and 34 is still high, National Grid decided in 2017 to issue an RFP for a battery storage solution. Battery power will be used to meet the remaining excess demand during peak load times, meaning that substation upgrades can be further deferred.

Marketing Effectiveness

- Pilot marketing efforts were effective in generating awareness of and interest in the various SRP offerings. Lead activity, as well as participation, tended to increase following outreach campaigns, particularly in 2013, the first full year of the pilot. In subsequent years, there was a much smaller increase in participation, suggesting that much of the “low hanging fruit” had been harvested.

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[2] The total cumulative kW reduction target was greater than 1 MW to allow for some loss of impacts due to DemandLink participants opting out of demand response events.

- Direct mail was consistently identified as the most recalled and memorable marketing channel among both participants and non-participants. More resource-intensive strategies, such as outbound phone calls for residential customers and door-to-door canvassing for small business customers, were also very successful, when deployed, and should be considered for future efforts (if budgets allow). Email outreach tended to be less memorable than other methods, but given its low cost is a good supplementary approach to other outreach methods.

- Throughout the course of the pilot, the EnergyWise Program had the highest levels of awareness and interest among the various pilot offerings. This is not surprising, given that EnergyWise is a long-running statewide program and is applicable to a broad range of residential customers. For future efforts, National Grid should continue to leverage programs like EnergyWise as a screening and channeling mechanism for other offerings. Future programs should also ensure that other program offerings are systematically promoted during the in-home assessments.

- Focus group participants expressed a desire for more transparent messaging around the demand response events and why National Grid had targeted Tiverton and Little Compton for the offering. The societal and community benefits of the program, including lower greenhouse gas emissions and improved grid reliability, were thought to be potential drivers of participation for customers who are not motivated by free equipment or bill savings. While National Grid began including a "Good for you/good for your community" theme in its messaging in 2014—mainly in newsletters and often combined with other offers and messaging—research conducted with residential leads in 2014 and 2015 suggests that this theme and the messaging around local benefits did not fully take hold among potential participants. For future community-focused efforts like the SRP pilot, National Grid should consider making community benefits a more central and clearly visible theme of outreach messaging, as they are often effective in motivating additional groups of customers. Incorporating the community name into the name of the pilot (e.g., the "Marshfield Energy Challenge"), if possible, can be another way of emphasizing the community-aspects of the program.

- While awareness of the various program offerings was generally high, it was lowest for the window AC recycling rebate, and that offering also had the lowest number of leads in 2014 and 2015. Messaging for this rebate was generally combined with information about other offerings and might therefore not have received much notice by customers. Yet, this offering accounted for 7% of pilot load impacts. For future efforts, to better promote offers like the window AC recycling rebate, National Grid should consider more focused messaging, e.g., in combination with a time-limited enhanced rebate, or an "event" like *Window AC Recycling Month*, which can be effective in promoting action by potential participants.

DemandLink Thermostat Program

- Savings from the DemandLink demand response events fell short of expectations, with only 36 kW, or 11% of total pilot load impacts, compared to a target of 590 kW.

- The DemandLink Thermostat Program encountered three challenges in realizing expected load reductions from demand response events: (1) low enrollment in the program; (2) significant connectivity issues, especially for participants with window AC; and (3) an event strategy that resulted in lower than expected hourly per household event savings.

Enrollment

- Enrollment in the program was limited, largely due to the small population in the pilot area and the low incidence of central AC among pilot area residents. Even among those that do have central AC, some customers questioned whether they use it enough to justify the need for supplemental equipment to automate a cooling schedule or to warrant participation in events. Adapting to these local circumstances, National Grid began offering plug devices to enable customers with window AC to participate in the program. However, this approach was plagued with technical issues such as low connectivity, even in the year when the participant enrolled and first installed the equipment, leading to few event participants. Following extremely low evaluation results, the plug device offering was discontinued in 2016. Given the challenges inherent in basing a demand response program on equipment that, by definition, will be removed every year, we do not recommend this approach for any future pilots.

Event Participation

- The high incidence of missing log files and log files with no data severely limited the load impacts realized by the program. While connectivity issues were not too surprising for customers with window AC, the high incidence of missing data for customers with central AC, especially in the final years of the pilot, was unusual. While National Grid did some investigations of the issue with Ecobee, the source of the problem was never fully diagnosed. For future programs, we recommend keeping a close eye on connectivity issues and asking for more accountability from the event implementer.

Event Strategy

- Savings per thermostat tended to be lower than generally seen for similar demand response programs. Several components of the event strategy chosen by the program contributed to this:
  - The program chose a 2°F offset strategy for customers with central AC, fearing that a cycling strategy or a higher offset would lead to participant dissatisfaction. However, small temperature offsets are subject to decreasing load impacts in later event hours, as the room temperature more quickly reaches the new setpoint. For example, average hourly impacts for the 2017 events were 0.75 kW for the first hour, 0.52 kW for the second hour, and 0.33 kW for the third hour. For future efforts, National Grid should consider using a cycling strategy, which would avoid the decrease in savings in later event hours, or a more aggressive offset strategy, e.g., of 3 or 4°F, which would reduce the decrease in savings.
  - In 2017, National Grid changed the length of its demand control events from 4 hours to 3 hours. This change helped avoid the near-zero savings observed in the last hour of prior events and resulted in the highest average hourly per thermostat savings across the four event seasons. For future efforts, National Grid should keep the shorter event length. National Grid should also ensure that events start as closely to the predicted peak demand as possible, so that the higher first-hour savings are realized during the times of highest demand. (In addition, most events have snapback that increases load for at least an hour after the event period. If events start too far ahead of peak conditions, snapback could occur during peak demand.)
  - The SRP event strategy did not include pre-cooling. Precooling is an effective approach for both offset and cycling strategies as it delays the room temperature reaching the new setpoint, thereby further reducing event time usage. For future efforts, National Grid should consider the addition of pre-cooling to its event strategy.
  - In 2017, National Grid called events when daytime temperatures, nighttime temperatures, or humidity forecasts met certain trigger conditions. In prior program years, events had been called

based on load forecasts, i.e., when peak demand was predicted. The 2017 strategy resulted in one-third of events being called when event time temperatures were very moderate (between 69 to 73°F); these events tended to have lower savings than events with higher event time temperatures. Calling events during moderate temperature conditions is justified if the demand reduction is needed at that time (based on load forecasts). If it is not needed, then these events will result in lower average event savings for the program. For future efforts, National Grid should ensure that events are called at times of predicted peak demand, rather than using trigger conditions, which may not well correlate with peak demand.

Enhanced Statewide Energy Efficiency Offerings

- National Grid's enhancement of existing statewide offerings, i.e., the EnergyWise Program, the SBDI Program, and the HPWH rebate, were the most successful component of the pilot, contributing 255 kW, or 81%, to total pilot load impacts.

EnergyWise Program

- SRP outreach efforts were successful in increasing annual EnergyWise participation rates from 1.1% prior to the pilot to 3.6% during the pilot period (an increase of 228%). In contrast, average annual participation rates in the comparison towns increased from 1.5% to 2.5% (an increase of 70%). Direct mailings, word-of-mouth, and outbound phone calls from National Grid were the most common ways for participants and leads to find out about the program.

- Research with program leads identified difficulty finding the time to be home for the assessment as the top barrier to participation. In addition, 10% of leads in the program reported challenges when they tried to schedule an appointment, including difficulty reaching a representative and limited options for appointments (including lack of weekend appointments and no available appointment for over a month). While program participation was generally strong, it did start to decline towards the end of the pilot period. For future efforts, National Grid should consider ways to reduce these barriers, e.g., by ensuring that appointments can be made in a timely fashion and at times that work for the prospective participants.

- Lighting measures accounted for the vast majority of savings, initially in the form of CFLs (2012-2013) and later in the form of LEDs (2014-2017). While these measures contributed significantly to deferring substation upgrades in the early years of the pilot, the changing baseline for residential lighting measures (due to new EISA standards) resulted in decreasing savings from these measures over time. As is the case for residential demand side management programs across the country, National Grid will have to diversify away from lighting measures for future efforts if it wishes to leverage this type of program in support of its peak load reduction goals.

SBDI Program

- Participation in the SBDI Program increased markedly in 2013 (from 2% prior to the pilot to 7%) because of increased outreach activity, including door-to-door canvassing. However, the program discontinued these efforts in 2014 because the door-to-door canvassing was expensive and small business opportunities were judged to be limited. As a result, participation returned to pre-pilot levels in 2014 and stayed at this level for the remainder of the pilot. Considering that the SBDI Program achieved over 50% of its 5-year participation in 2013—and accounted for almost one-third of cumulative pilot load impacts—the pilot may have missed an opportunity for additional savings, by discontinuing small business outreach efforts after 2013. For future efforts, National Grid should consider continued small business outreach, even if using less expensive outreach channels, especially if residential opportunities are limited.

HPWH Rebate

- Introduced in 2015, the HPWH rebate had a relatively small impact on overall pilot savings (2% of pilot totals). Receipt of the HPWH rebate was tied to participation in the DemandLink Thermostat Program, which can be an effective strategy in promoting other program offerings. For future efforts, National Grid should carefully examine the effect of this conditionality on rebate participation and monitor participation in the other offerings: Based on SRP pilot tracking data, only four of 27 HPWH participants in 2015 and 2016 were also enrolled in the DemandLink Thermostat Program.

New SRP-Specific Energy Efficiency Offerings

- To capitalize on the high incidence of window AC in the pilot area, National Grid introduced two new SRP-specific window AC rebate opportunities in 2013. Overall, these new rebates generated 25.2 kW in peak load reductions (or 8% of pilot totals). The majority of these impacts came from recycling inefficient window AC units without replacing them with a new unit. Savings from the purchase of new efficient window AC units or the recycling of inefficient units with replacement, on the other hand, generated relatively small savings.

- A majority of non-participants were unaware of the available rebates for purchasing new efficient window AC units (57%) and recycling old inefficient units (71%). However, the potential customer base eligible to receive a rebate for purchasing a new window AC unit was quite large: Almost 4 out of 10 customers (39%) used or planned to use window AC to cool their home in the summer, and 35% of those window AC users (or 14% of all customers) were likely to purchase a new window AC unit in 2017. In addition, 19% of customers had window AC units that they no longer used or that they were thinking about replacing in 2017.

1. Introduction

Feeders 33 and 34 of the Tiverton substation serve approximately 4,200 residential and 1,000 commercial customers in the coastal Rhode Island communities of Tiverton and Little Compton. In 2010, National Grid forecasted that these feeders would be capacity-constrained during summer afternoon peak hours starting in 2014. Weighing the cost of substation upgrades against non-wires alternatives, National Grid designed the System Reliability Procurement (SRP) pilot with a goal of reducing summer peak demand by up to 1 MW by 2017, thus deferring substation upgrades to at least 2018. Plans for the SRP non-wires alternative were filed and approved in 2012.

1.1 Program Offerings

National Grid used a three-pronged strategy to pursue its SRP peak demand reduction goals: (1) implementation of the DemandLink Programmable Controllable Thermostat Program, a new SRP-specific demand response offering, (2) enhancement of existing statewide energy efficiency offerings, and (3) introduction of new SRP-specific energy efficiency offerings. All three components were supported by an intensive and targeted marketing and outreach campaign that began in March 2012.

DemandLink Programmable Controllable Thermostat Program

The DemandLink Thermostat Program provided temperature control devices to pilot-area customers. All participants received a WiFi-enabled programmable thermostat. Customers with window air conditioning (window AC) also received one or more plug devices, which allowed the WiFi-enabled thermostat to control their window AC unit(s). To be eligible, customers had to have a WiFi internet connection and either central air conditioning (central AC) or window AC, and they had to agree to participate in demand optimization events for at least two years. Customers received an annual bill credit for participating in all demand optimization events.

During 2016, the pilot discontinued offering plug devices and began enrolling new pilot participants with central AC through the statewide Connected Solutions Demand Response Program. National Grid began calling demand response events in July 2014. During the first summer, only three events were called. Between 2015 and 2017, National Grid called between 15 and 18 events per summer. Events lasted for four hours in 2014 to 2016 and for three hours in 2017.

Enhanced Statewide Energy Efficiency Offerings

National Grid provided increased incentives and conducted targeted customer outreach for three existing statewide energy efficiency offerings:

- **EnergyWise Home Energy Assessment Program.** The EnergyWise Program provides residential customers with a home energy assessment and a range of direct install measures. Beginning in 2014, the program offered customers in the pilot area LEDs instead of CFLs.
- **Small Business Direct Install (SBDI) Program.** The SBDI program is the commercial equivalent of the EnergyWise program, targeting small non-residential customers.
- **Electric Heat Pump Water Heater (HPWH) Rebate.** In 2015, National Grid began offering customers an enhanced rebate of $1,100 (compared to a $750 rebate offered through the statewide program) for the purchase of a new electric HPWH. To be eligible for the rebate, customers had to participate in the DemandLink Thermostat Program.

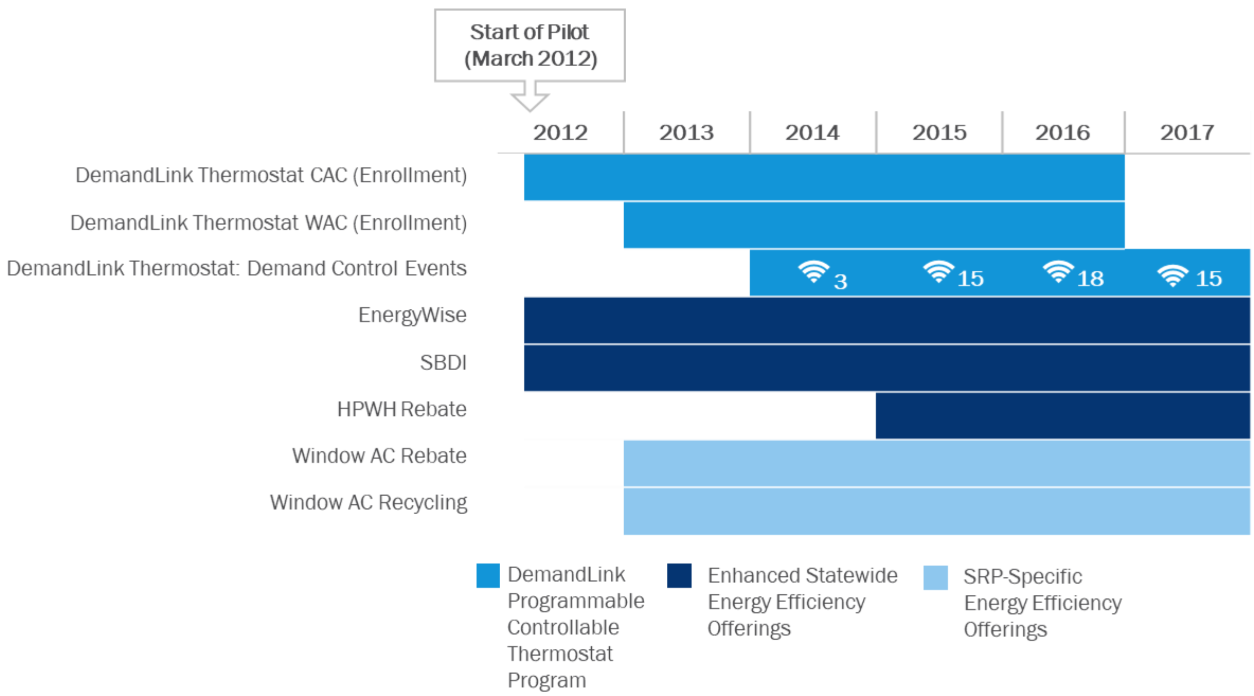
SRP-Specific Energy Efficiency Offerings

To capitalize on the high incidence of window AC in the pilot area, National Grid introduced two new SRP-specific window AC rebate opportunities in 2013. Both rebates were available each year between May 1st and November 1st:

- **DemandLink Window AC Rebate Program.** Customers in Tiverton and Little Compton could receive a $50 rebate for the purchase of qualifying new window AC units, up to four units per household. Eligible units included those with an energy efficiency ratio (EER) greater than or equal to 10.8.
- **DemandLink Window AC Recycling Program.** Customers in Tiverton and Little Compton could receive a $25 rebate for window AC units they recycled, up to four units per household.

Figure 1-1 summarizes the timeline of the various program offerings.

Figure 1-1. Timeline of Program Offerings



1.2 Evaluation Activities

National Grid Rhode Island contracted with Opinion Dynamics to conduct annual evaluations of the SRP pilot. Throughout the pilot, evaluation activities were focused on two main topics: (1) the effectiveness of marketing activities in promoting and increasing program participation and (2) the load impacts realized by the pilot. In addition, some of the evaluations covered process-related topics such as drivers of and barriers to participation and participant experience during demand response events.

In support of the annual evaluations, Opinion Dynamics conducted a range of primary data collection activities, including several surveys with EnergyWise and DemandLink participants, two residential leads surveys, a general population survey, a DemandLink event follow-up survey, and a non-participant focus group. Impact analyses included application of deemed savings values to estimate EnergyWise and SBDI load impacts as well as HPWH savings; development of per unit savings estimates for window AC rebates; and estimation of central AC and window AC DR event impacts using regression analysis. Each annual evaluation concluded with an annual evaluation report.

The findings and conclusions presented in this report are drawn from these annual evaluations. The objective of this summary report is to provide a big picture synthesis of the pilot's efforts, including what worked well and what did not work well, as well as lessons learned for potential future pilots. This report therefore does not repeat detailed findings from the earlier evaluation reports. However, where helpful, we include supporting information in the appendices and provide references to the earlier evaluation reports.

Appendix A presents a summary of the evaluation activities and key deliverables completed for each year of the SRP pilot.

1.3 Organization of Report

The remainder of this report presents key impact and process evaluation findings for the Rhode Island SRP pilot. It is organized as follows:

- Section 2 presents an overview of Marketing and Outreach Efforts including a summary of campaign activities and an assessment of marketing effectiveness.
- Section 3 presents key participation, impact, and process findings for the DemandLink Thermostat Program.
- Section 4 presents key participation, impact, and process findings for the Enhanced Statewide Energy Efficiency Offerings, i.e., the EnergyWise Program, the SBDI Program, and the HPWH rebate.
- Section 5 presents key participation and impact findings for the SRP-Specific Energy Efficiency Offerings, i.e., the window AC rebates.
- Section 5 presents key conclusions and recommendations.
- Section 7 presents references, including the various evaluation reports upon which the findings in this report are based.
- Appendix A provides additional detail on the evaluation activities performed over the course of the pilot.
- Appendix B provides additional detail on EnergyWise gross impacts
- Appendix C provides additional detail on EnergyWise net impacts
- Appendix D provides additional detail on SBDI gross impacts
- Appendix E provides additional detail on SBDI net impacts

2. Marketing and Outreach Efforts

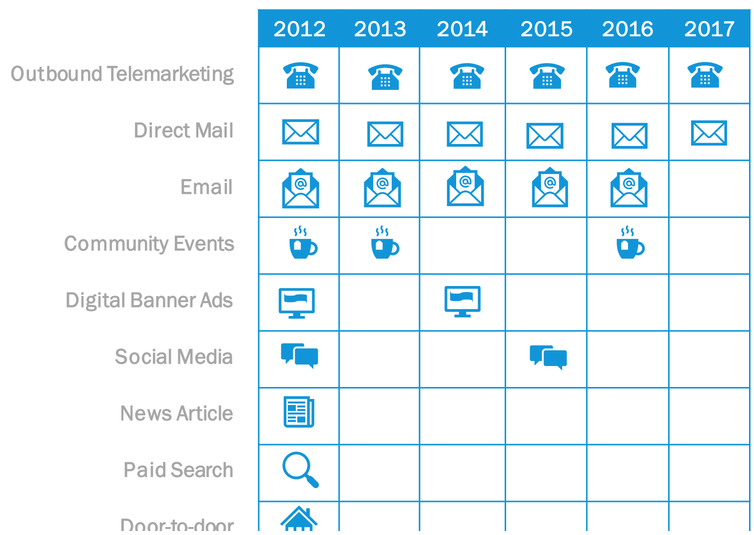
Starting in 2012, National Grid increased marketing and outreach to encourage participation in select existing statewide energy efficiency programs as well as new programs that were offered exclusively to customers in the Tiverton and Little Compton pilot area.

2.1 Summary of Campaign Activities

National Grid deployed a multi-touch, multi-channel marketing campaign to reach customers over the course of the pilot and encourage participation in the various program offerings. While messaging was disseminated through a variety of channels, the cornerstone of the campaign consisted of outbound telemarketing, direct mail, and email. Throughout the campaign, marketing materials provided customers with a phone number or email address to contact program staff and learn more about the offerings. RAM Marketing received these calls and emails and directed qualified customers to RISE Engineering to sign up for the EnergyWise and DemandLink Thermostat programs.

Although the pilot officially started in March 2012, marketing activities did not begin to ramp up until June 2012, targeting residential customers. Marketing towards commercial customers started in August 2012. In the first program year, the campaign targeted DemandLink messaging to customers who had previously had an audit through the EnergyWise Program or who were identified as having historically high summer usage. Marketing activities to small businesses focused on door-to-door outreach. In 2013, National Grid began deploying marketing activities much earlier in the year, with the first materials going out to customers by mid-April. The campaign shifted its focus from targeting specific lists of customers and began including all pilot area customers in its outreach. It also increased the frequency of direct mail, email, and outbound telemarketing.

Figure 2-1. SRP Marketing Channels 2012-2017



The campaign held one community event in both 2012 and 2013. In 2016, the campaign enlisted volunteers to staff information tables and promote the pilot offerings at local organizations and community events between June and September.

Figure 2-1 provides a summary of channels employed throughout the campaign, by year.

National Grid typically kicked off campaign activities in April each year, deployed the bulk of messaging in the late spring and summer months, and ramped activities down through the fall. Telemarketing activities typically closely followed key direct mail campaigns. Figure 2-2 provides an example of the annual timeline of marketing activities for a typical year.

Figure 2-2. 2016 SRP Marketing Timeline

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Direct Mail				■	■		■	■		■	■	
Email									■			■
Telemarketing					■	■		■	■			
Community Outreach						■	■	■	■			

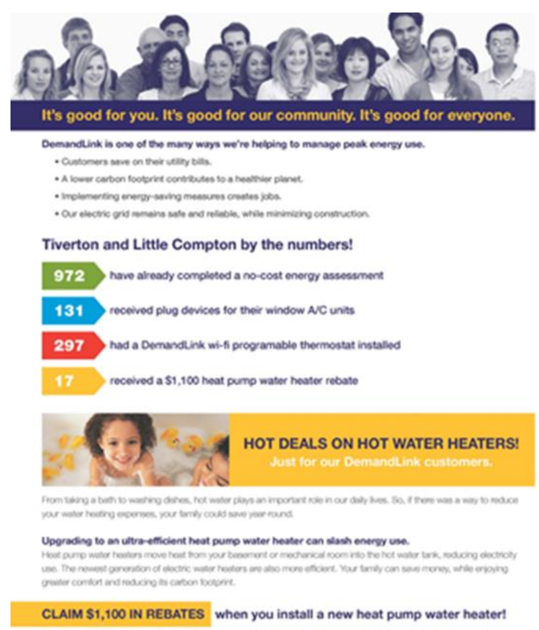
Messaging in 2012 and 2013 centered around a "Save money/save energy" theme. Prompted by focus group findings in late 2013, the pilot added a "Good for you/good for your community" theme beginning in 2014. This theme focused on positioning the DemandLink Program as beneficial to both the participant and the local community. National Grid also launched the LinkUp newsletter in 2014, which grounded DemandLink as a program designed to benefit the community by preventing the need to build additional infrastructure. The newsletter provided updates on participation counts, called non-participants to sign up, and provided current participants with additional tips on using their thermostat and plug devices throughout the year.

Starting in 2015, marketing pieces also began to include information on the HPWH rebate as well as reminders for participants to reinstall removed devices and check that the WiFi thermostats and the plug devices were connected to their internet.

September 2012 Email

Summer 2016 Post Card

October 2016 Newsletter



2.2 Marketing Effectiveness

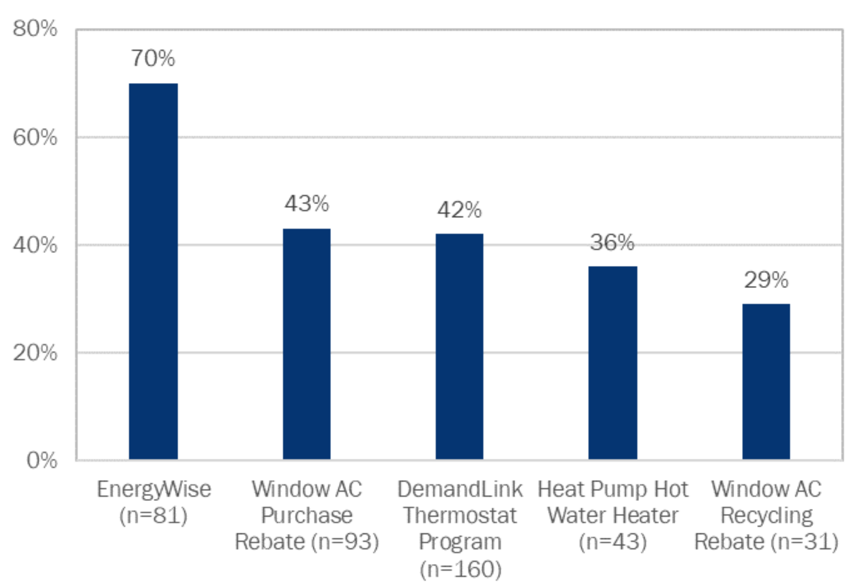
To assess the effectiveness of the pilot's marketing and outreach efforts, all annual evaluations included primary research with participants, leads, and/or non-participants. In specific, Opinion Dynamics conducted focus groups with non-participants in late 2013; online surveys with EnergyWise participants following the 2013, 2014, 2015, and 2017 program years; telephone surveys with residential leads in early 2015 and 2016; and an online general population survey in early 2017. Covered topics included awareness of and interest in the various program components, recall of specific marketing materials, and the effectiveness of those materials in inducing program participation.

2.2.1 Program Awareness

Based on the pilot's outreach strategy, all customers in Tiverton and Little Compton should have received multiple pilot-related messages through various marketing channels over the course of the pilot period. To assess the effectiveness of these outreach efforts, we fielded a general population survey in early 2017 after close to five years of SRP marketing. This survey asked about customer awareness of the various SRP program components. Among non-participants, survey results showed the highest levels of awareness with the EnergyWise Program (70%). This is not surprising, given that EnergyWise is a long-running statewide program and is applicable to a broad range of residential customers. Awareness of other program components, although lower, was strong as well, with over 40% reporting awareness of the SRP-specific window AC purchase rebate and the DemandLink Thermostat Program. Awareness of the HPWH rebate, which was introduced in 2015, and the window AC recycling rebate were lowest, at 36% and 29%, respectively.

These results suggest that the program did a good job overall, making pilot area residents aware of the various SRP offerings.

Figure 2-3 Awareness of Program Components (Non-Participants)



Source: PY2016 General Population Survey

2.2.2 Program Interest

Another indicator of effective marketing is heightened lead activity following outreach efforts. SRP leads are customers who expressed interest in one or more SRP program offerings (through inbound requests or outbound telemarketing) but had not yet participated in that program offering. To correlate lead activity with marketing efforts, Opinion Dynamics, in support of the 2015 annual program evaluation, conducted an analysis of 2013-2015 tracking data compiled by RISE and RAM.

Overall, the program recorded 628 residential leads in 2014 and 555 residential leads in 2015. In both years, the vast majority (over 80%) of SRP leads were interested in the EnergyWise Program. Interest in the other SRP programs was much lower, and leads in all program components decreased between 2014 and 2015.

Table 2-1. 2015 Customer Interest by Program

SRP Program	2014 Leads		2015 Leads	
	Count	% [a]	Count	% [a]
EnergyWise Program	526	84%	450	81%
DemandLink Programmable Controllable Thermostat Program	173	28%	84	15%
DemandLink Window AC Rebate Program	76	12%	31	6%
DemandLink Window AC Recycling Program	69	11%	20	4%
Total Leads (Any Program)	**628**		**555**	

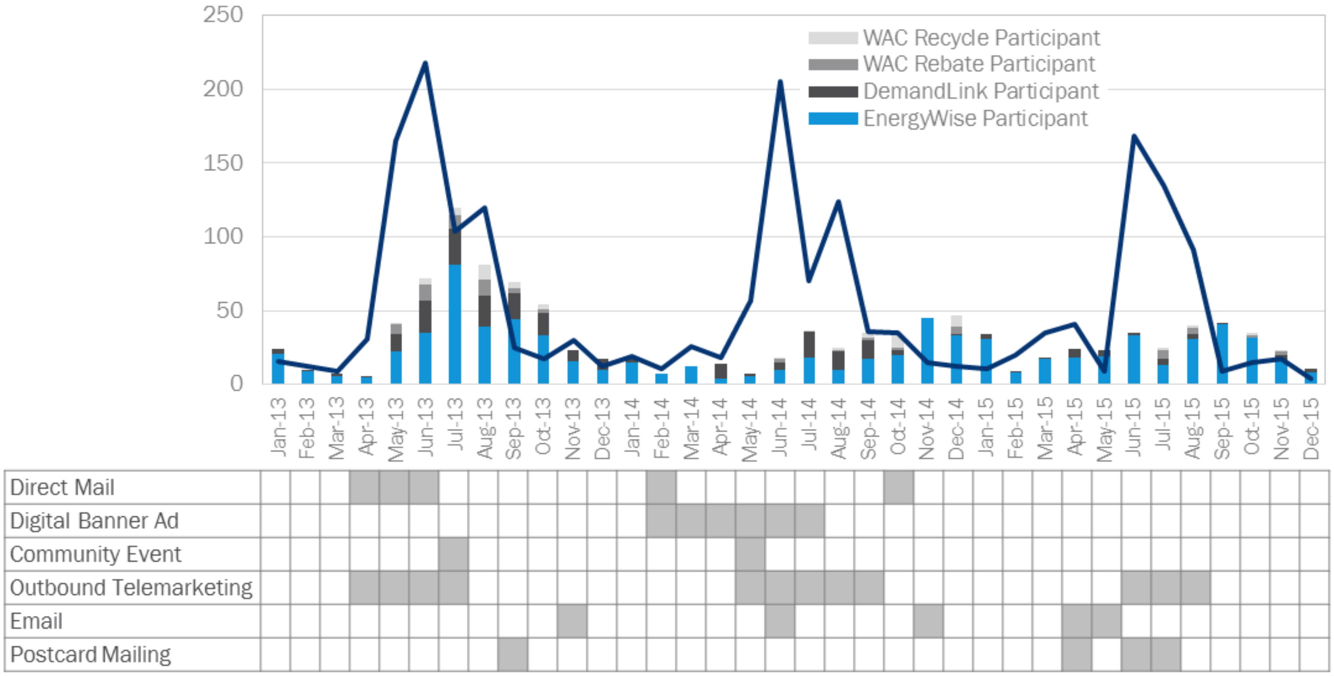
Source: PY2015 Residential Leads Analysis

[a] Total sums to more than 100% because some customers expressed interest in multiple programs.

Heightened lead activity followed increases in marketing efforts in the spring and early summer of 2013, 2014, and 2015, suggesting success in generating program interest. Program tracking data also shows an increase in participation, following the peak in leads. This spike in participation is especially pronounced in 2013, the first full year of the pilot. Subsequent years show a much smaller increase in participation, suggesting that much of the "low hanging fruit" had been harvested.

Figure 2-4 summarizes lead activity and participation between 2013 and 2015.

Figure 2-4. Program Leads in SRP Pilot Communities (2013-2015)



Source: PY2015 Residential Leads Analysis

2.2.3 Effectiveness of Different Outreach Channels

In addition to program awareness, the 2017 general population survey also explored customer recall of 2016 marketing activities, including specific outreach materials (a newsletter, a post card, and an email) as well as the effectiveness of these materials in stimulating interest in participation.

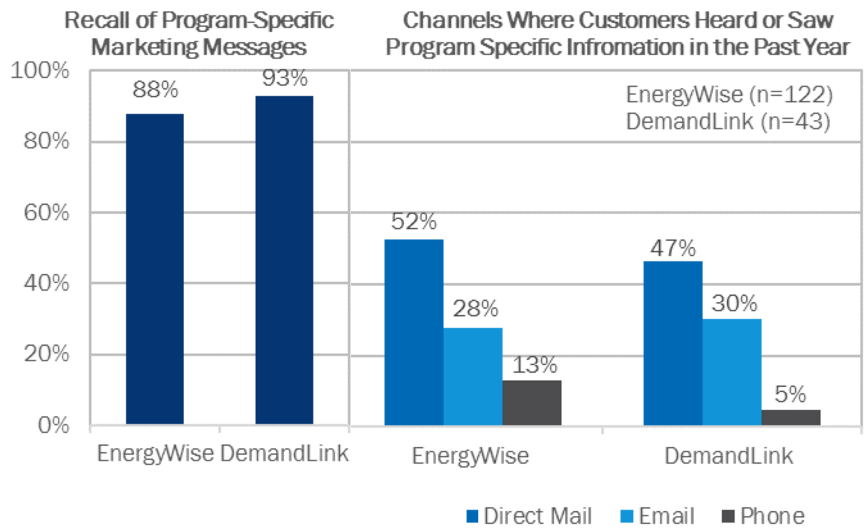
General Recall of Messaging

The survey first asked customers if they recalled hearing or seeing any information about each program component during 2016.[3]

Participant recall of messaging about components in which they had already participated (in 2016 or prior years) was very high, with 88% of EnergyWise and 93% of DemandLink participants remembering receiving program information in 2016. These participants most often recalled receiving information in the mail (52% and 47%, respectively). Program participants less frequently remembered receiving emails (28% and 30%, respectively) or phone calls (13% and 5%, respectively) from the pilot. Figure 2-5 summarizes these findings.

[3] These questions were only asked of customers who had heard of the program component prior to the survey. Customers who reported not owning their home did not receive questions about the HPWH rebate, and customers who did not plan to use window AC or to recycle a window AC unit in 2017 did not receive questions about window AC rebates.

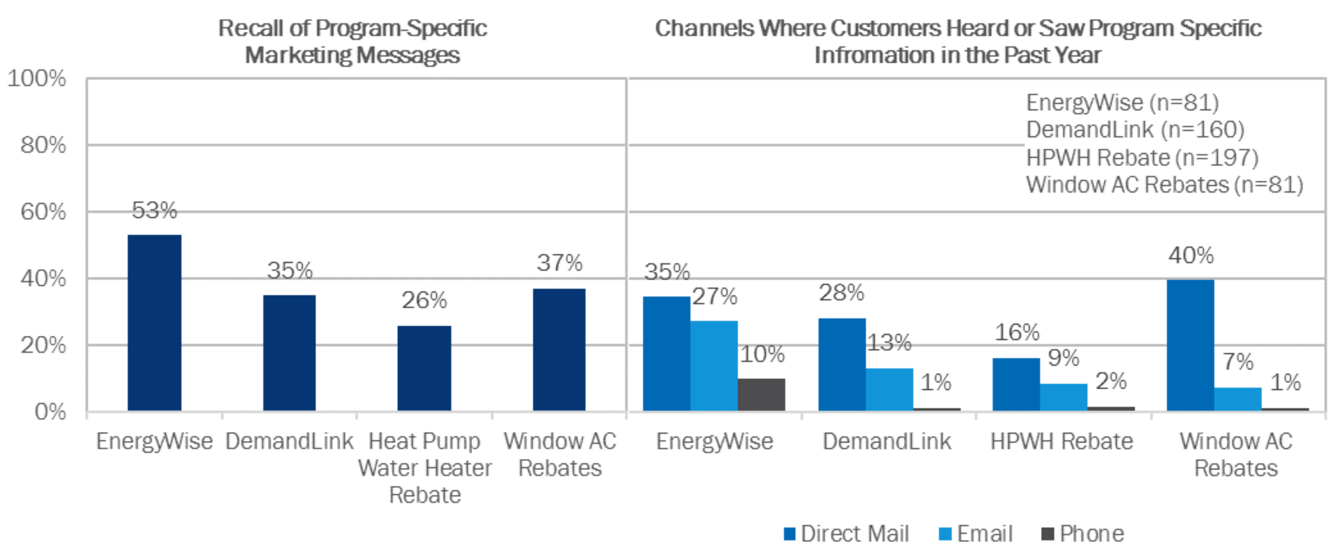
Figure 2-5. Recall of Program-Specific Marketing Messages (Participants)



Source: PY2016 General Population Survey

Recall of component-specific messaging among non-participants was lower compared to participants, but still high: 53% of customers who had not yet participated in the EnergyWise Program remembered receiving information about it 2016, most often in the mail. Recall rates for other program components were significantly lower (37% for window AC rebates, 35% for DemandLink, and 26% for HPWH rebates), yet still relatively high. Across all components, non-participants were most likely to remember information they received in the mail.

Figure 2-6. Recall of Program-Specific Marketing Messages (Non-Participants)



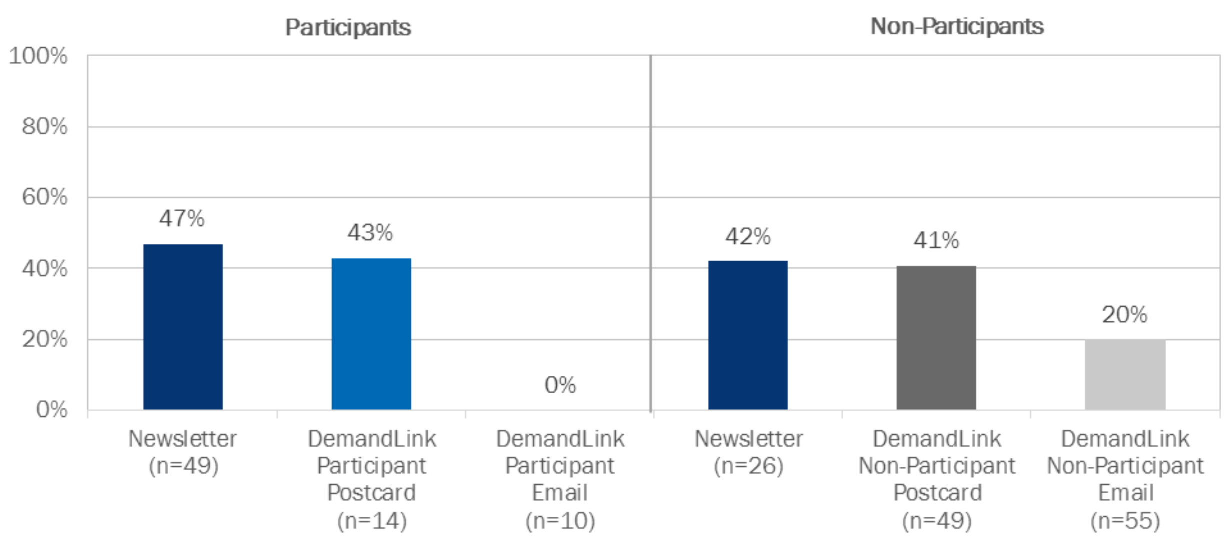
Source: PY2016 General Population Survey

Recall of Specific Marketing Materials

To assess the effectiveness of messaging used by the pilot in 2016, the 2017 general population survey included detailed questions about three key marketing pieces: a postcard sent in August, a newsletter sent in October, and an email sent in December. DemandLink participants and non-participants received different versions of the postcard and email, each with messaging tailored to their participation status. The online survey showed respondents images of the materials and assessed customer recall of the specific materials as well as prior familiarity with the content.

Figure 2-7 shows respondent recall of the key marketing pieces. In general, the direct mail pieces were more memorable than the emails, and participants and non-participants tended to recall the materials at similar rates. Recall rates by non-participants are relatively high, at 42% for the newsletter, 41% for the postcard, and 20% for the email.[4]

Figure 2-7. Recall of Marketing Materials



Source: PY2016 General Population Survey

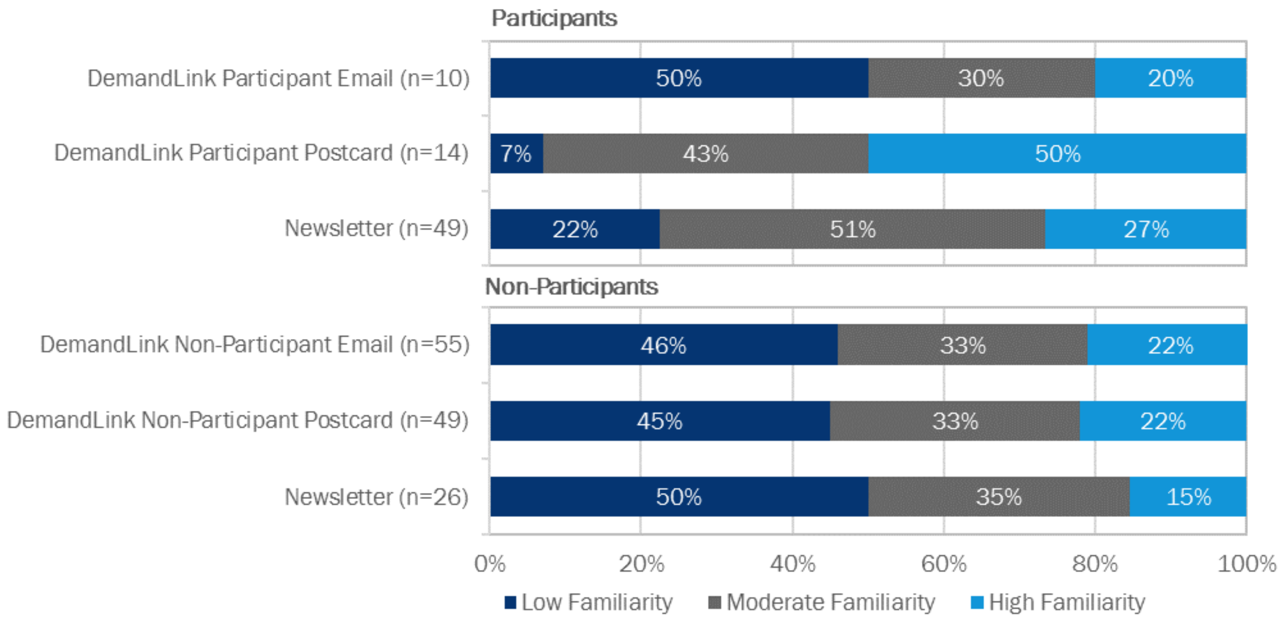
After reviewing the materials, respondents were asked how much of the information in the images was new to them. We used this question to assess the degree to which past program messaging is remembered by customers. We categorized customers who indicated that none or very little of the information was new as having "high familiarity" while those who indicated that most or all of the information was new as having "low familiarity."

Overall, DemandLink participants had the highest level of familiarity with the content of the postcard (50% high familiarity; 43% moderate familiarity), followed by participant familiarity with the content of the newsletter (27% high familiarity; 51% moderate familiarity). Non-participant familiarity was relatively consistent across the three outreach channels and comparable to DemandLink participant familiarity with

[4] The utility industry standard for email open rates is (22%). Considering a customer has to open an email to recall it, a recall rate of 20% suggest an open rate that is in line with, or exceeds, what would be expected for email outreach. (Source: Questline, 2015 Energy Utility Email Benchmarks Report available at: https://cdn.questline.com/asset/get/47a2f0f7-f0fd-4917-b7b6-2625e84ef911)

the content of the email: all had a level of high familiarity between 15% and 22% and a level of low familiarity between 45% and 50%.

Figure 2-8. Recall of Information Provided by Marketing Material (By Participation Status)



Source: PY2016 General Population Survey

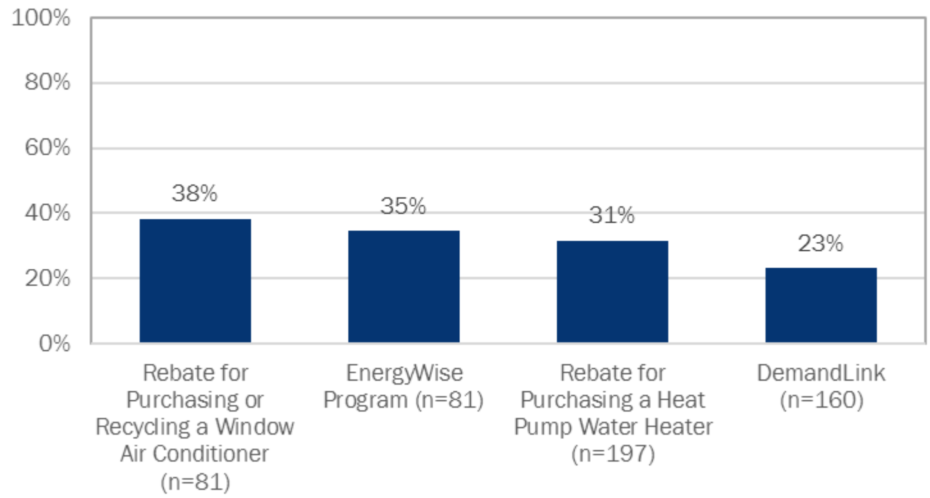
Interest in Programs after Review of Messaging

The final set of questions in the 2017 general population survey assessed customers' likelihood to visit the pilot's website or get more information about one or more of the offerings, following their review of the materials. Overall, 48% of respondents reported being likely[5] to seek out more information.

Of non-participants eligible to participate in the various components, about one-third were interested in seeking more information about window AC rebates (38%), the EnergyWise Program (35%), and the HPWH rebate (31%). Significantly fewer DemandLink Thermostat Program non-participants were likely to seek more information about that program (23%).

[5] A rating of 3 or greater on a 5-point scale, where 1 means "not at all likely" and 5 means "very likely".

Figure 2-9. Interest in More Information About Program (Non-Participant in Program Component)



Source: PY2016 General Population Survey

2.2.4 Understanding of DemandLink Thermostat Offering

Two key findings from the 2013 non-participant focus groups included (1) a desire for more transparent messaging around the demand response events and why National Grid had targeted Tiverton and Little Compton for the offering; and (2) societal and community benefits of the program, including lower greenhouse gas emissions and improved grid reliability, are potential drivers of participation for customers who are not motivated by free equipment or bill savings. In response to these findings, the pilot added a "Good for you/good for your community" theme beginning in 2014. This theme focused on positioning the DemandLink Program as beneficial to both the participant and the local community.

To test the effectiveness of this new messaging, the residential leads survey (fielded in early 2016) explored how well leads in the DemandLink Thermostat Program understood various components of the program, including its community benefits. In specific, leads who were familiar with the program and who had not already scheduled an equipment installation appointment, were asked about their awareness of several key aspects of the pilot program.[6] Survey results showed the following:

- Most respondents were aware that WiFi-enabled programmable thermostats allow users to remotely control their central or window AC (13 out of 15 respondents) and that National Grid provides participants with WiFi-enabled programmable thermostats at no cost (12 respondents).
- Less than half of interviewed leads (6 respondents) were aware that the program is only available to customers with central or window AC or that the program is only available to customers in Tiverton and Little Compton.
- Out of the program aspects asked about in the survey, customers were least aware that the program helps delay the need for an upgrade to a local substation (3 respondents). This suggests that the program's attempts to emphasize benefits to the community (beginning in 2014 with the marketing message of *"Good for you. Good for our community. Good for everyone.")* did not fully take hold among potential program participants.

[6] Of 43 interviewed leads, four had already scheduled an appointment for the installation of DemandLink equipment and 24 were not at all familiar with (or unaware of) the program. These questions were therefore asked of 15 leads.

- Similarly, few interviewed leads (5 respondents) were aware that participation in the program includes participation in demand optimization events called by National Grid.

3. DemandLink Thermostat Program

The DemandLink Thermostat Program was a key SRP-specific offering designed to directly address peak load conditions through demand response events. The goal of the program was to reduce electricity usage during times of peak load (generally hot summer afternoons) by controlling the air conditioning usage of program participants via WiFi-enabled programmable controllable thermostats.

3.1 Program History

The program began providing WiFi-enabled thermostats to customers with central AC in 2012. However, due to the relatively low incidence of central AC in the pilot area, the program added plug devices in 2013. The plug devices allowed the WiFi-enabled thermostat to control window AC units, thereby expanding program eligibility to customers with window AC units. To participate in the program, customers had to have a WiFi internet connection and either central AC or window AC, and they had to agree to participate in demand optimization events for at least two years. Customers received an annual bill credit for participating in all demand optimization events in a given summer.

The program began calling demand response events in July 2014. During the first summer, only three events were called. These events lasted from 3 p.m. to 7 p.m. for central AC units and from 4 p.m. to 6 p.m. for window AC units. For central AC, setpoints were increased by 2°F; for window AC, the unit was shut off for the duration of the event. In 2015 and 2016, the program called 15 and 18 events, respectively, with event durations and cycling strategies similar to those used in 2014.

Annual impact evaluations of the 2014, 2015, and 2016 events showed lower than expected overall savings due to several factors: (1) overall enrollment in the program was limited: a total of 208 thermostats controlling central AC and 158 thermostats controlling window AC were in place during the 2016 event season; (2) there were significant connectivity issues, especially for participants with window AC, meaning that a large share of enrolled customers never had the chance to participate in the events; and (3) hourly event savings per household were lower than in other similar programs, which was partially due to the relative conservative setback strategy of 2°F and the long event duration of four hours. In response to these results, the pilot discontinued offering plug devices in 2016 and did not include participants with window AC in the 2017 events. In addition, anticipating the end of the pilot in late 2017, the program began enrolling new participants with central AC through the statewide Connected Solutions Demand Response Program. These enrollees were included in the SRP-specific events as well as events called for Connected Solutions.

The program made additional changes to its event strategy in 2017. In prior summers, events had been called based on forecasted hot weather. In 2017, on the other hand, events were called if forecasted conditions for daytime temperatures, nighttime temperatures, or humidity exceeded trigger points. In addition, the event time was more closely linked to forecasted peak demand, which falls between 2 pm and 8 pm. Finally, the event duration was reduced from four to three hours, based on negative savings during the last event hour found in prior evaluations.

3.2 DemandLink Thermostat Participation

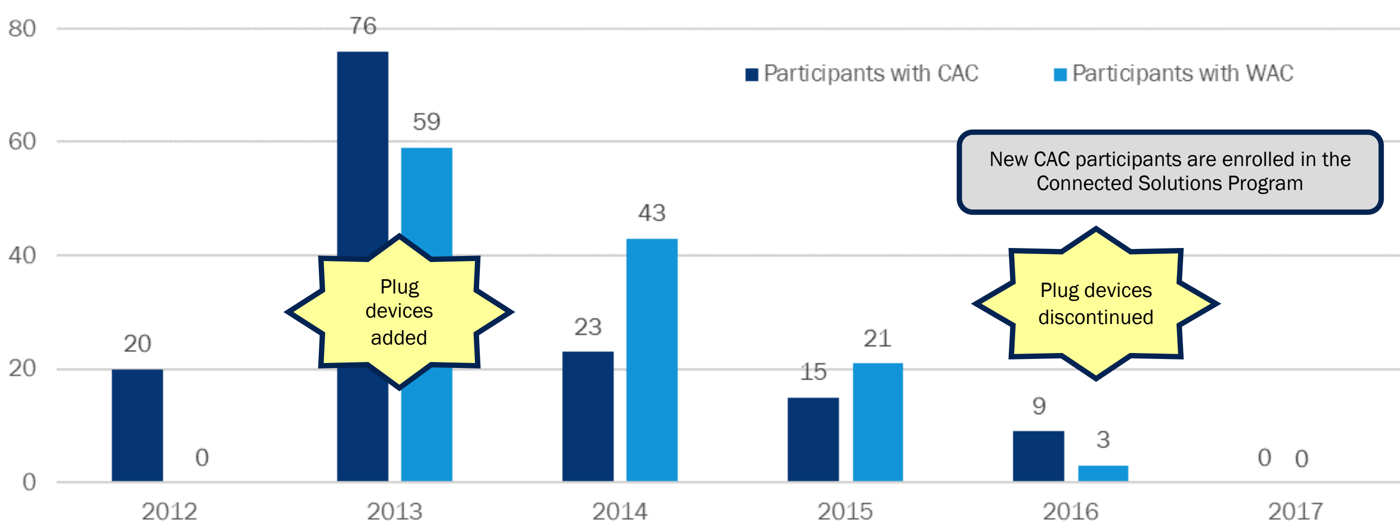
Participation in a demand response program can be divided into two stages: (1) enrollment and (2) event participation. Both stages are necessary for the program to realize load impacts. The DemandLink Thermostat Program experienced challenges in both stages, as described below, leading to lower than expected savings.

3.2.1 Enrollment

Between March 2012 and the end of 2016, 269 customers signed up to participate in the DemandLink Thermostat Program, 143 with central AC and 126 with window AC. In total, participants with central AC installed 229 thermostats (an average of 1.6 per home) and participants with window AC installed 300 plug devices (an average of 2.4 per home). Enrollment of new participants peaked in 2013, with 135 new participants.

Overall, enrollment of customers with central AC fell short of initial projections as many households in the pilot area do not have central AC. As a result, the program began offering plug devices to enable customers with window AC to participate in the program. However, due to connectivity issues, the plug device option was discontinued in 2016. Figure 3-1 summarizes annual enrollment in the DemandLink thermostat program component, by type of AC unit and first year of participation.

Figure 3-1. DemandLink Thermostat Program Enrollment by Year in SRP Pilot Communities (2012 - 2017)



Source: Program Tracking Data

3.2.2 Event Participation

In addition to lower than expected enrollment, participation in the demand response events was low as well. This was largely due to connectivity issues, especially for plug devices, which were likely removed during the fall and not always reinstalled during the next summer, or not reconnected to the WiFi thermostat.

Analysis of thermostat log files for the four summer event seasons (2014-2017) shows several unusual trends with respect to event participation:

- A progressively smaller share of installed thermostats participated in the events: for thermostats controlling central AC, the participation rate fell from 73% in 2014 to 27% in 2017; for thermostats controlling window AC, the participation rate fell from 22% in 2014 to 0% in 2016.
- Conversely, the share of thermostats for which no log file data was available (either because there was no log file or because the log file did not contain any valid data) increased over the pilot period, from 14% in 2014 to 66% in 2017 for thermostats controlling central AC and from 77% in 2014 to

99% in 2016 for thermostats controlling window AC. Notably, the share of missing/invalid log files for window AC was already 77% in 2014, the first year that demand response events were called, indicating the considerable challenges associated with this type of demand control strategy.

- Event failures (defined as thermostats that did not respond to the event, either because they were offline or because they did not receive the signal to begin the event) were moderate for central AC thermostats, ranging from 5% to 10% of all installed thermostats. While the overall event failure rate was lower for window AC thermostats, event failure as a percentage of non-missing/invalid log files was similar to that of central AC thermostats.
- Event opt-outs (defined as thermostats that received the event signal, but the setting switched out of event mode and the AC unit began cooling before the end of the event) were also moderate, ranging from 2% to 12% for participants with central AC and less than 1% for participants with window AC (the latter again driven by the large number of thermostats with missing/invalid log data).

Based on this analysis, the overall non-participation rate—defined as thermostats with missing log files/no data *plus* event failures—increased from 23% to 71% for central AC participants and from 78% to 99% for window AC participants. As noted above, these non-participation rates were largely driven by thermostats with missing log files or log files with no data. While event failure rates for the SRP pilot were fairly typical, overall non-participation rates were not.[7]

Table 3-1 summarizes the results of the thermostat log file analysis.

Table 3-1 Summary of Demand Response Event Participation

	2014[a]		2015[a]		2016		2017	
Central AC								
Thermostats Installed	205		228		208		208	
Event Participant	150	73%	122	54%	91	44%	56	27%
Opt-out	8	4%	28	12%	15	7%	4	2%
Event Failure	18	9%	23	10%	10	5%	11	5%
Missing Log File/No Data	29	14%	55	24%	91	44%	138	66%
Window AC								
Thermostats Installed	123		150		158		n/a	
Event Participant	27	22%	11	7%	0	0%		
Opt-out	0	0%	1	<1%	0.4	<1%		
Event Failure	1	1%	2	1%	0	0%		
Missing Log File/No Data	95	77%	136	91%	157	99%		

Source: PY2014-2017 Thermostat Log Files

[a]2014 and 2015 thermostat counts include customers in Tiverton and Little Compton who are not in the pilot area.

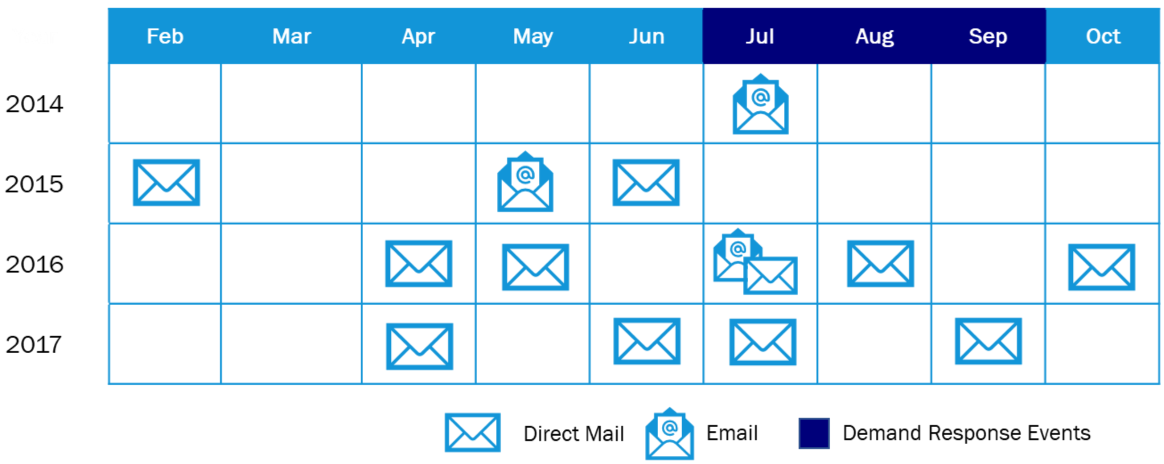
Given the significant impact of missing log files/data on program savings (see next subsection), National Grid implemented several mitigation strategies: (1) At the beginning of the event season, Opinion Dynamics examined thermostat log files and provided Ecobee, the event implementer, with a list of thermostats with missing log files/data. This strategy was intended to rectify any potential connectivity issues in the event portal. (2) Prior to the event season, National Grid began reaching out to past participants to remind them to

[7] More typical non-participation rates for central AC programs are between 10% and 20%. Since window AC demand response programs are uncommon, comparison non-participation rates for the window AC component are not available.

reinstall any removed devices and check that the WiFi thermostats and the plug devices are connected to the participant's internet. This strategy was intended to rectify any connectivity issues on the customer end.

Figure 3-2 summarizes the outreach conducted to reduce customer-related connectivity issues. The reminder email deployed in July 2016 was targeted specifically at participants whose thermostats were offline and reminded them to connect their thermostats. All other outreach was delivered in conjunction with other program messages.

Figure 3-2 Thermostat Connectivity Messaging



Despite the reminder messages, overall connectivity did not increase. Survey research with DemandLink participants between 2014 and 2016 indicated that a significant and increasing portion of plug devices (42% in 2014, 47% in 2015, 68% in 2016) were not being used with window ACs during the cooling season. Not unexpectedly, survey results also showed that usage of plug devices with window AC units was lower for participants who had the equipment installed in a prior year, suggesting that at least some customers were not reconnecting their window AC units to the plug devices at the start of new cooling season.

3.3 DemandLink Thermostat Impacts

Opinion Dynamics used regression modeling combined with day matching to estimate the demand response load impacts for window AC participants and the runtime reduction for central AC participants. The load impact for central AC events was then calculated by multiplying the runtime reduction by the mean full load demand, to arrive at the demand response attributable to the event. (See the annual evaluation reports for 2014, 2015, and 2016 for more detail on our methodology.)

For participants with central AC, the average runtime reduction ranged from 9% to 15% for the four event seasons. The corresponding per thermostat impacts ranged from 0.32 kW to 0.52 kW. For participants with window AC, we only developed regression-based impact estimates for 2014 (0.07 kW per thermostat) and 2015 (0.04 kW per thermostat). By 2016, the number of usable log files was insufficient to develop a new regression model, and we estimated the 2016 per thermostat impact as the weighted average of 2014 and 2015.

Annual program impacts were calculated as the per thermostat kW impact multiplied by the number of thermostats included in the analysis.[8] Given that few new devices were installed after the peak in 2013, the increasing number of thermostats with missing log files/data means that progressively fewer thermostats could be included in our analysis. As a result, even though the per thermostat impacts for central AC were highest in 2017, the small number of thermostats included in the analysis resulted in the lowest program impacts of the four event seasons. This trend is even more pronounced for participants with window AC, where program impacts approached zero in 2016.

Table 3-2 summarizes demand response impacts for the four program years.

Table 3-2 Summary of Demand Response Impacts

Program Year	# of Events	Per-Thermostat Impact		Mean # of Thermostats in Analysis[b]	Program Impact (kW)
		Runtime Reduction	kW[a]		
Central AC					
2014	3	8.6%	0.32	176	56
2015	15	13.3%	0.49	155	76
2016	18	10.9%	0.40	115	46
2017	15	14.8%	0.52	68	36
Window AC					
2014	3	n/a	0.07	28	2.0
2015	15	n/a	0.04	14	0.6
2016	15	n/a	0.045[c]	0.4	0.018
2017	n/a				

Source: PY2014-2017 Gross Impact Analyses

[a] Impacts in this table are average impacts across all event hours. The average first-hour impacts were 0.26 for 2014, 0.87 for 2015, 0.91 for 2016, and 0.72 for 2017.

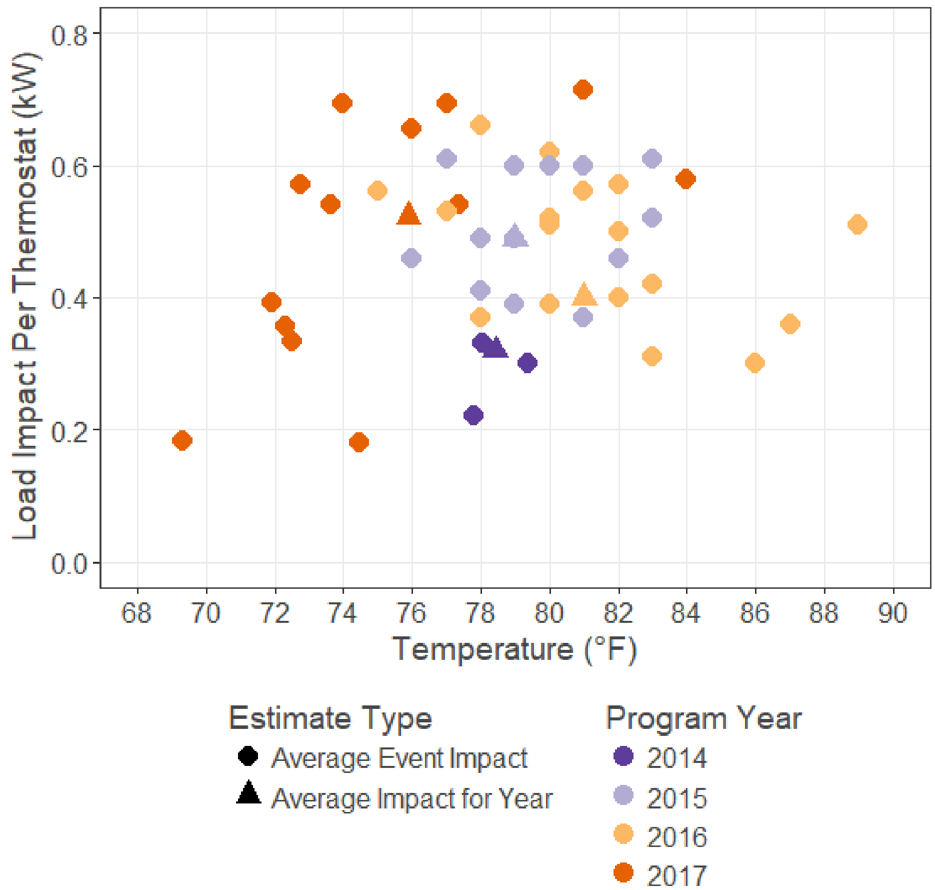
[b] The number of thermostats in the analysis differs slightly from the number of participating thermostats above as thermostats in the analysis include opt-outs and certain types of event failures.

[c] Due to the small number of thermostats with valid data, the 2016 per thermostat kW impact was estimated as the weighted average of the 2014 and 2015 kW impacts.

Figure 3-3 provides a visual depiction of the average per-thermostat load impacts plotted against the average temperature during event hours. The figure includes each event over the four program years as well as the average for each program year.

[8] The number of thermostats included in the analysis includes event participants, opt-outs, and certain types of event failures.

Figure 3-3 Average Per-Thermostat Load Impact by Temperature



3.4 DemandLink Thermostat Key Process Findings

Over the course of the SRP pilot, Opinion Dynamics administered two surveys with DemandLink Thermostat Program participants, one DR event follow-up survey, two residential leads surveys, as well as a general population survey and focus groups with non-participants. Based on this research, the following key process findings emerged:

- Saving energy and money was the primary driver to program interest and participation. Other drivers included the opportunity to receive free equipment and the ability to remotely control the thermostat. Customers with window AC were less interested in remotely monitoring or controlling equipment than customers with central AC. Early focus groups also identified benefits to the community as strong motivators.
- While the program focus was on air conditioning, the ability to monitor and control *heating* equipment was a more compelling driver for some customers, due to the relatively mild summer climate and low air conditioning usage in the pilot area.
- Based on non-participant focus groups and surveys of program leads, the pilot faced several key barriers to participation:

  - Lack of understanding of how the program worked, what the main benefits were, and how those benefits applied to customers;
  - The perception that customers do not use their air conditioning enough to justify the need for supplemental equipment to automate a cooling schedule or to warrant participation in events;
  - Technical concerns including how the WiFi thermostat would interface with their existing HVAC systems;
  - Concern around letting someone else control their thermostat during events; and
  - Concern about uncomfortable humidity levels during events.
- More than half of DemandLink Thermostat leads (56%) were either unaware of the program or not at all familiar with it (a rating of 1 on a scale of 1 to 5). Only 12% of DemandLink Thermostat leads considered themselves very familiar with the program.
- Participants reported continued installation and use of 99% of installed WiFi thermostats during the 2016 cooling season. All interviewed respondents with central AC reported using at least one of their thermostats to control their central AC system. Not surprisingly, participants with window AC reported lower rates of installation and continued use of their plug devices: 73% had one or more plug devices not in use during the 2016 cooling season.
- Participants with central AC were highly aware of the various elements of the DemandLink Thermostat Program; awareness of participants with window AC was systematically lower. Findings from both the 2015 DemandLink Participant Survey and 2016 DemandLink Event Follow-Up Survey suggested that participants with Window AC who were not aware of the events were less likely to plug their window ACs into their plug devices.
- The 2016 DemandLink Event Follow-Up Survey showed moderate participant awareness of the August 29th, 2016 event: 57% of those with central AC and 50% of those with window AC were aware that the event had been called. Among participants with central AC, close to half (47%) were home during the event and 10% reported opting-out of the event, due to discomfort or the anticipation of discomfort. Among respondents with window AC, only 17% were home during the event, and none reported opting out.
- Research with participants throughout the pilot period indicated uniformly high satisfaction with the equipment installed through the program. Areas of dissatisfaction among participants with window AC included the inability to connect to the thermostat to the plug devices and not knowing how to use the equipment.
- Almost all interviewed participants (95%) said they planned to participate in future events.

4. Enhanced Statewide Energy Efficiency Offerings

A second key strategy of the SRP pilot was increasing pilot area participation in existing statewide programs through enhanced marketing and increased incentives. National Grid offered enhancements to three statewide energy efficiency offerings: the residential EnergyWise Program, the commercial SBDI Program, and the heat pump water heater incentive.

Below, we present highlights for each of these three offerings.

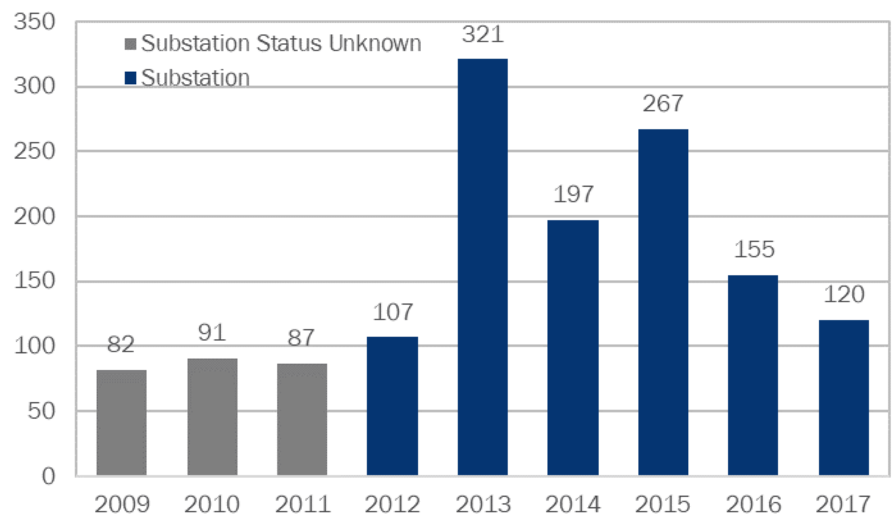
4.1 EnergyWise Program

Beginning in March 2012, National Grid conducted targeted customer outreach in the pilot area to promote participation in the statewide EnergyWise Program, which provides residential customers with a home energy assessment and a range of direct install measures. In addition to contributing directly to pilot area impacts, the program served as an important recruitment and screening tool for the DemandLink Thermostat Program.

4.1.1 EnergyWise Participation

In total, 1,167 customers in the pilot area participated in the EnergyWise Program during the pilot period, an average of 195 participants per year. This compares to average annual participation levels of less than 90 prior to the start of the pilot (see Figure 4-1).

Figure 4-1 EnergyWise Participants in SRP Pilot Communities (2009-2017)[a]



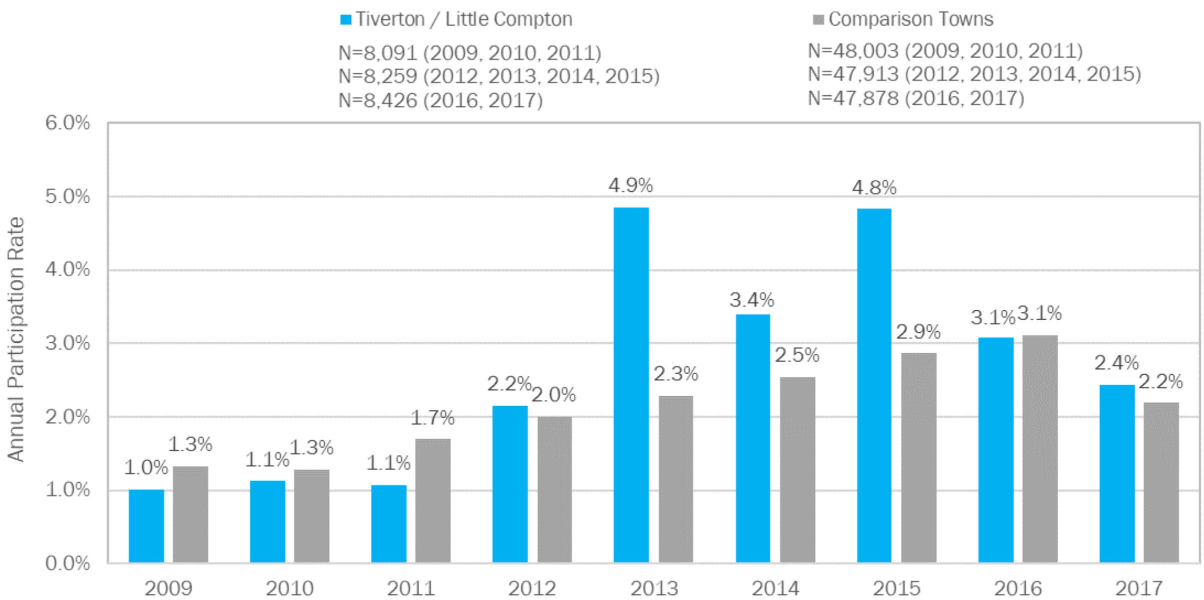
Source: Program Tracking Data

[a] Participant counts for the pre-pilot period 2009-2011 include non-substation participants.

Given that EnergyWise was an existing, statewide program, a key question when assessing the success of the pilot is: *To what extent did the pilot increase participation relative to what it would have been without the pilot?* Or in other words: *What was the* incremental participation *due to the enhanced SRP efforts?* We estimated incremental participation in the pilot area by comparing participation rates (calculated, for each year, as the number of participants divided by the number of occupied households) for the pilot area with participation rates in a set of matched comparison towns.[9] Based on this comparison, we can determine what expected participation rates in the pilot area would have been, if only the statewide program had existed.

Results of the incremental participation analysis show that average annual participation rates in Tiverton and Little Compton increased from 1.1% prior to the pilot to 3.6% during the pilot period (an increase of 228%). In contrast, average annual participation rates in the comparison towns increased from 1.5% to 2.5% (an increase of 70%). These participation rates translate into actual pilot area participation 48% higher than what would have been expected in the absence of the SRP pilot,[10] suggesting that the SRP marketing campaign indeed had a positive impact on participation in the EnergyWise Program. Figure 4-2 compares the annual participation rates in Tiverton and Little Compton and the comparison communities.

Figure 4-2 EnergyWise Participation Rates in SRP Pilot and Comparison Towns, 2009-2017



Source: Program Tracking Data; American Community Survey (2012, 2014, 2016)

Note: This analysis includes both substation and non-substation participants in Tiverton and Little Compton

4.1.2 EnergyWise Impacts

Pilot area participants in the EnergyWise Program generated 152.4 kW in cumulative gross impacts (see Table 4-1).[11] As is often the case with residential assessment programs, lighting measures accounted for the vast majority of savings, initially in the form of CFLs (2012-2013) and later in the form of LEDs (2014-2017). However, given the changing baseline for residential lighting measures, due to changing EISA standards,

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[9] The matched comparison towns are Narragansett, North Kingstown, South Kingstown (excluding URI), Bristol, Barrington, and Warren. For a detailed discussion of the selection of the comparison communities, see National Grid Rhode Island System Reliability Procurement Pilot: 2012-2013 Focused Energy Efficiency Impact Evaluation, by Opinion Dynamics Corporation, dated May 12th, 2014.

[10] For detailed discussion of the EnergyWise incremental participation rate calculation methodology, see National Grid RI SRP 2015 Annual Evaluation Report, by Opinion Dynamics, dated August 3, 2016.

[11] Calculated for each measure i as $\text{Peak Load Reduction (kW)}_i = \text{Quantity}_i * \text{per Unit kW Reduction}_i * \text{Summer Diversity Factor}_i$

savings from these measures have been decreasing over time.[12] Nevertheless, the EnergyWise Program accounted for the largest share of cumulative SRP peak load impacts, with 48% of the pilot total.

Table 4-1 summarizes the annual installations, and peak load savings, from EnergyWise measures. The cumulative measure quantity is equal to the sum of installations throughout the pilot period. The cumulative peak load reduction, however, excludes savings from measures in the early years, once the measures have reached the end of their useful life.[13]

Appendix B presents a more detailed overview of gross peak load reduction for all EnergyWise measures. Appendix C presents the estimated "take rate" as well as net impacts for the program.

Table 4-1 EnergyWise Installed Measures and Annual Gross Peak Load Impacts: March 2012-2016

Measure Category	2012	2013	2014	2015	2016	2017	Cumulative
Quantity Installed							
LED Bulb	87	998	3,946	10,973	5,060	3,952	25,016
CFL	2,382	8,670	1,867	233	47	0	13,199
Smart Strip	60	539	363	568	347	232	2,109
Refrigerator Brush	103	297	191	253	158	111	1,113
Other	37	285	140	142	95	121	820
TOTAL	**2,669**	**10,789**	**6,507**	**12,169**	**5,707**	**4,416**	**42,257**
Peak Load Reduction (kW; *excluding measures that have reached the end of their useful life*)							
LED Bulb	0.5	5.3	21.0	58.5	27.0	21.1	133.3
CFL	1.9	6.8	1.5	0.2	<.1	-	10.3
Smart Strip	0.2	1.6	1.1	1.7	1.0	0.7	6.0
Refrigerator Brush	0.1	0.3	0.2	0.3	0.2	0.1	1.0
Other	0.1	0.9	0.3	0.2	0.1	0.1	1.8
TOTAL	**2.7**	**14.9**	**24.0**	**60.8**	**28.3**	**22.0**	**152.4**

Source: Program Tracking Data; PY2017 Gross Impact Analysis

4.1.3 EnergyWise Key Process Findings

Over the course of the SRP pilot, Opinion Dynamics administered four online surveys with EnergyWise participants, two residential leads surveys, and one general population survey. Based on this research, the following key findings emerged:

- The EnergyWise Program tended to have higher awareness and attract more interest than other SRP offerings throughout the course of the pilot period.
- Based on the 2016 leads survey, only 22% of EnergyWise leads had ever had an energy assessment at their home, and over half of those assessments (56%) had taken place five or more years ago. This indicates an opportunity for the EnergyWise Program to reach a new audience among its customers.

[12] Each annual evaluation applied the kW reduction of the program year under evaluation. As a result, the 2012-2016 results presented here do not match results presented in the prior annual evaluation reports.
[13] Savings excluded because of measures' end of useful life include torchieres installed in 2012 and 2013 (with an expected useful life of 4 years) as well as 2012 smart strips and refrigerator brush measures (with an expected useful life of 5 years).

- EnergyWise leads most often learned about the program through direct mailings from National Grid (43%), followed by friends and colleagues (21%), National Grid outbound phone calls (18%), and emails (9%).
- The opportunity to save energy and money were the most common reasons for interest in the EnergyWise Program, noted by almost 9 out of 10 leads (87%). The "free" aspects of the program, including the audit itself and the free measures, were also attractive program attributes (43%). Getting information on home energy usage was of less interest (21%).
- While barriers to participation in the EnergyWise Program varied, difficulty finding the time to be home for the assessment was consistently identified as the top barrier. While program participation was generally strong, it did start to decline towards the end of the pilot period.
- EnergyWise leads most often reported having taken no further action towards receiving an EnergyWise assessment since they first learned about the program (59%). Those who had taken action most frequently spoke with a program representative (32%), spoke with someone who participated in the program (24%), or looked online to learn more about the program (16%). Notably, 27% of 2015 EnergyWise leads had already scheduled an energy assessment by the time we conducted the survey in January of 2016. Together with the 48% of all 2015 EnergyWise leads that had already participated, this indicates good success in getting interested customers into the program.
- A number of EnergyWise leads reported difficulty scheduling the appointment for their assessment. Notably, of EnergyWise leads that had tried to schedule an assessment but had not actually scheduled it at the time of the survey, 80% reported having difficulty doing so (representing 10% of all EnergyWise leads). Reasons cited by individual respondents included difficulty reaching a representative, limited options for appointments (including lack of weekend appointments and no available appointment for over a month), and personal scheduling difficulties.

4.2 Small Business Direct Install Program

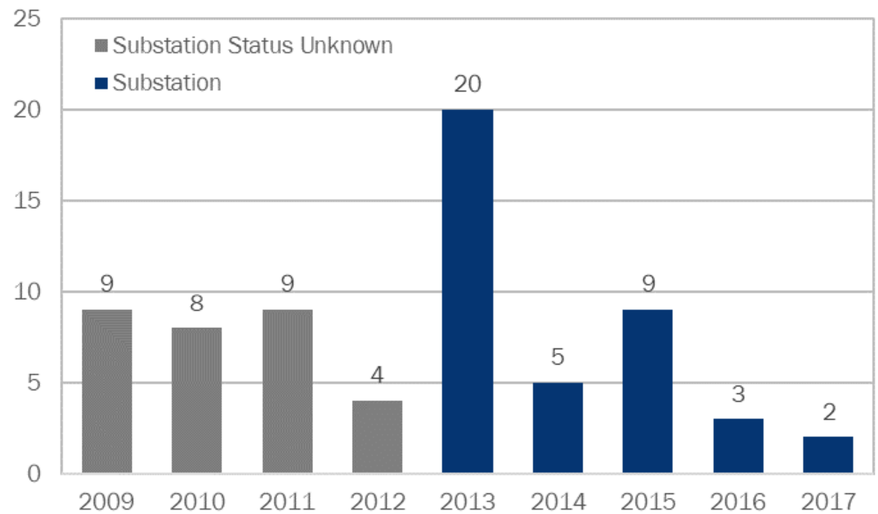
In August 2012, the pilot began enhanced outreach for the statewide SBDI Program, the commercial equivalent of the EnergyWise Program, targeting small non-residential customers. Initial efforts included door-to-door outreach in 2013. However, this strategy, while successful in 2013, was soon discontinued because it was expensive and implementation staff saw little opportunity among the very small businesses. As a result, the later years of the pilot saw little to no targeted effort to increase SBDI Program participation among commercial customers.

4.2.1 SBDI Participation

In total, 39 small commercial customers in the pilot area participated in the SBDI program during the pilot period, an average of 8 participants per year. This compares to average annual participation levels of just under 8 prior to the start of the pilot (see Figure 4-3).

Participation in the SBDI Program increased markedly in 2013, as a result of increased outreach activity, including door-to-door canvassing. However, participation returned to pre-pilot levels in 2014 and stayed at this level for the remainder of the pilot. Considering that the SBDI Program achieved over 50% of its 5-year participation in a single year—and ended up accounting for almost one-third of cumulative pilot load impacts—the pilot may have missed an opportunity for additional savings, by discontinuing small business outreach efforts after 2013.

Figure 4-3 Small Business Direct Install Participation in SRP Pilot Communities: 2015-2017a



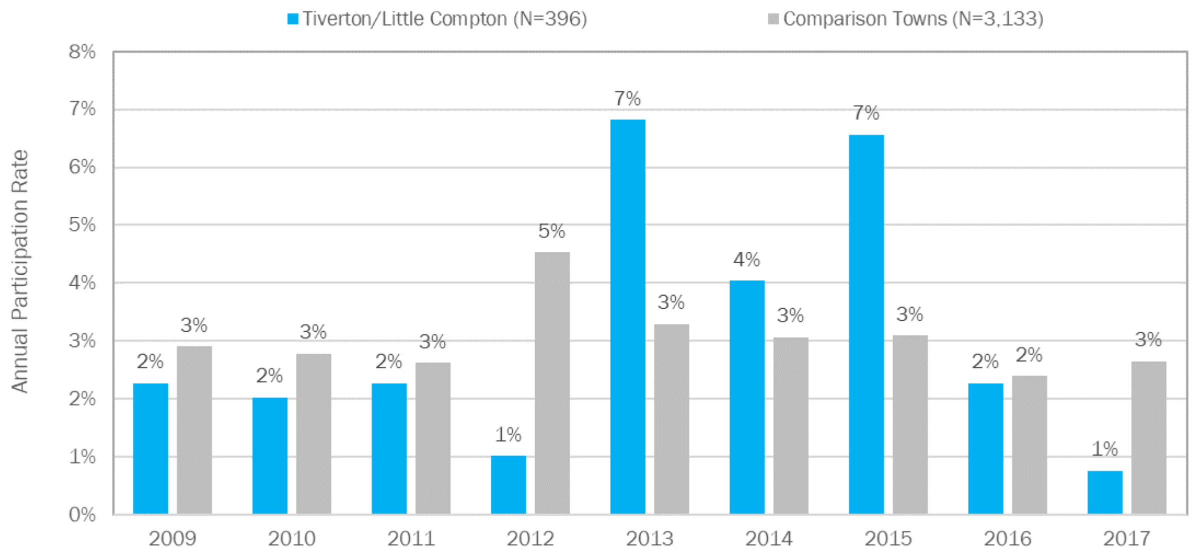
Source: Program Tracking Data
[a] Participant counts for the pre-pilot period 2009-2011 include non-substation participants.

To assess the effect of the SRP pilot, above and beyond what the statewide SBDI Program would have likely achieved, we conducted an incremental participation analysis similar to that conducted for the EnergyWise Program (see Section 4.1.1).[14]

Results of this analysis show that average annual participation rates in Tiverton and Little Compton increased from 2.1% prior to the pilot to 3.8% during the pilot period (an increase of 82%). In contrast, average annual participation rates in the comparison towns increased from 2.9% to 3.1% (an increase of 9%). These participation rates translate into actual pilot area participation 40% higher than what would have been expected in the absence of the SRP pilot, suggesting that the 2013 SRP outreach indeed had a positive impact on participation in the SBDI Program, even when considered over the full 5-year pilot period. Figure 4-4 compares the annual participation rates in Tiverton and Little Compton and the comparison communities.

[14] For detailed discussion of the SBDI incremental participation rate calculation methodology, see National Grid RI SRP 2015 Annual Evaluation Report, by Opinion Dynamics, dated August 3rd, 2016.

Figure 4-4 SBDI Participation Rates in SRP Pilot and Comparison Towns, 2009-2017a



Source: Program Tracking Data; American Community Survey (2012, 2014, 2016)

[a] This analysis includes both substation and non-substation participants in Tiverton and Little Compton

4.2.2 SBDI Impacts

Pilot area participants in the SBDI Program generated 96.4 kW in cumulative gross impacts (see Table 4-2), or 31% of cumulative pilot load impacts. Similar to the EnergyWise Program, LEDs were the dominant measure, accounting for 66% of cumulative demand savings. No non-lighting measures were installed by substation customers after 2014.

Table 4-2 summarizes the annual installations, and peak load savings, from SBDI measures. The cumulative values are equal to the sum of measure quantities and kW load reduction, respectively, throughout the pilot period. In contrast to the EnergyWise Program, no SBDI measures installed during the pilot period had reached the end of their useful life by 2017.

Appendix D presents a more detailed overview of gross peak load reduction for all SBDI measures. Appendix E presents net impacts for the program.

Table 4-2. SBDI Installed Measures and Annual Gross Peak Load Impacts: 2013-2016

Measure Category	2013	2014	2015	2016	2017	Cumulative
Total Measure Quantity						
LED Bulbs	982	12	305	90	152	1,541
Linear Fluorescent Lighting	320	89	10	0	0	419
Custom Lighting	0	0	2	1	0	3
HID Lighting	0	10	6	9	0	25
Other	42	43	11	12	0	108
TOTAL	**1,344**	**154**	**334**	**112**	**152**	**2,096**
Total Peak Load Reduction (kW)						
LED Bulbs	44.2	0.9	8.7	4.0	5.9	63.6
Linear Fluorescent Lighting	12.7	3.2	0.7	<0.1	<0.1	16.6
Custom Lighting	<0.1	<0.1	8.4	0.2	<0.1	8.6
HID Lighting	<0.1	1.3	0.8	0.1	<0.1	2.2
Other	1.1	3.8	0.4	0.1	<0.1	5.5
TOTAL	**57.9**	**9.2**	**19.0**	**4.4**	**5.9**	**96.4**

Source: Program Tracking Data; PY2017 Gross Impact Analysis

4.2.3 SBDI Key Process Findings

Given that the pilot deemphasized efforts for non-residential customers early on, the annual pilot evaluations did not include process analyses specific to non-residential customers or the SBDI Program.

4.3 Heat Pump Water Heater Program

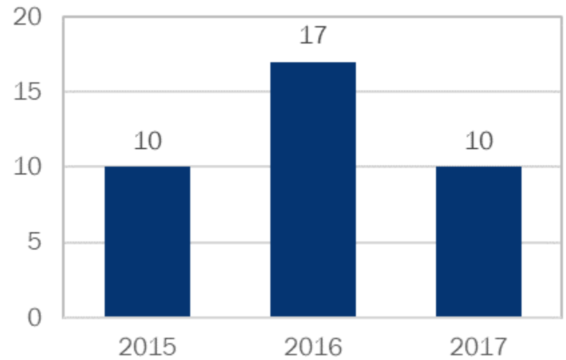
To further diversify the range of pilot offerings, National Grid, in 2015, began offering customers an enhanced rebate of $1,100 (compared to a $750 rebate offered through the statewide program) for the purchase of a new electric HPWH. To be eligible for the rebate, customers had to also participate in the DemandLink Thermostat Program.

4.3.1 HPWH Participation and Impacts

In total, 37 customers in the pilot area received enhanced rebates for installing heat pump water heaters between 2015 and 2017 (Figure 4-5), generating 5.9 kW in cumulative gross impacts for the pilot.[15]

[15] Calculated as Peak Load Reduction (kW) = Quantity * per Unit kW Reduction * Summer Diversity Factor

Figure 4-5. HPWH Rebate Participation in SRP Pilot Communities: 2015-2017



Source: Program Tracking Data

4.4 Key HPWH Process Findings

The annual evaluations did not include process work specific to the HPWH rebate. However, the 2017 general population survey explored awareness of and interest in the HPWH rebate among customers who own their home and have not yet participated in the program.

- Given that the HPWH rebate was a relatively new offering at the time of the survey, non-participating homeowners reported a relatively high awareness of the rebate (36%) and likelihood[16] to purchase a new HPWH through the program (38%). Not surprisingly, those who had previously considered replacing their current water heater (22% of non-participating homeowners) had higher levels of awareness and a significantly higher likelihood to participate than those who had not considered doing so (78% of non-participating homeowners).
- Non-participating homeowners who indicated a low likelihood[17] to participate in the program in 2017 had recently installed a new water heater (39%) or are simply not interested/do not feel that they need a new water heater (23%). Another 17% indicate they use a different type of water heater and are not interested in switching.
- After review of marketing materials related to the HPWH rebate, a majority of non-participants thought that the materials made it clear that signing up for the DemandLink Thermostat Program was a condition for receiving the rebate (noted by 66% who reviewed the newsletter and 56% who reviewed the DemandLink non-participant email).

[16] A rating of 3 or greater on a 5-point scale, where 1 means "not at all likely" and 5 means "very likely".
[17] A rating of 1 or 2 on the same 5-point scale.

5. SRP-Specific Energy Efficiency Offerings

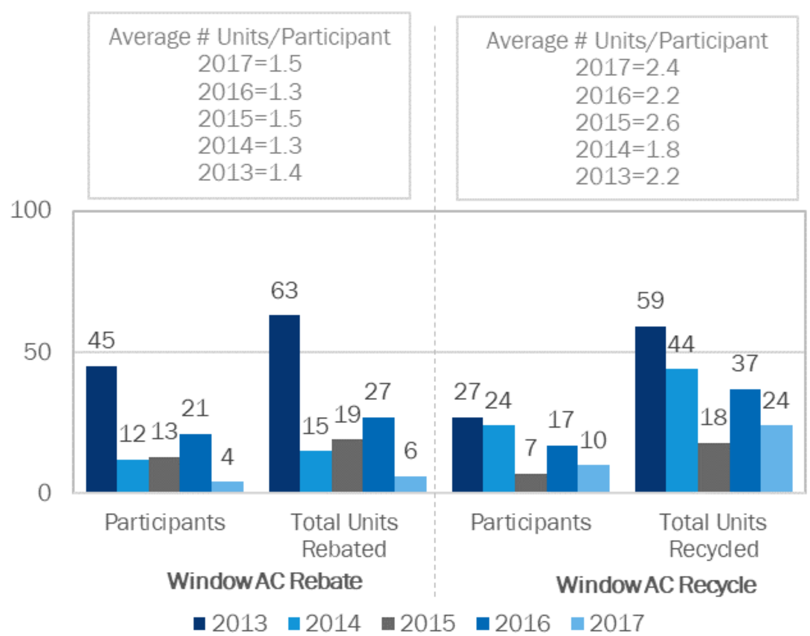
To capitalize on the high incidence of window AC in the pilot area, National Grid introduced two new SRP-specific window AC rebate opportunities in 2013. Both rebates were available each year between May 1st and November 1st:

- **DemandLink Window AC Rebate Program.** Customers in Tiverton and Little Compton could receive a $50 rebate for the purchase of qualifying new window AC units, up to four units per household. Eligible units included those with an energy efficiency ratio (EER) greater than or equal to 10.8.
- **DemandLink Window AC Recycling Program.** Customers in Tiverton and Little Compton could receive a $25 rebate for window AC units they recycled, up to four units per household.

5.1.1 Window AC Rebate Participation

In total, 95 customers in the pilot area received window AC rebates for installing 130 new ENERGY STAR® units, while 85 received rebates for recycling 185 old units (Figure 5-1). Participation in both programs peaked in 2013, the first year the rebates were offered. On average, participants recycled more units (between 1.8 and 2.6) than they purchased through the rebate program (between 1.3 and 1.5).

Figure 5-1 Window AC Rebate and Recycling Participation in SRP Pilot Communities: 2013-2017



Source: Program Tracking Data

5.1.2 Window AC Rebate Impacts

Since rebates for the purchase and recycling of window ACs are a new SRP-specific offering, no Rhode Island TRM values for these measures existed at the time of our evaluations. As such, Opinion Dynamics developed per unit savings values[18] and applied these to the quantities incented by the SRP pilot.

Table 5-1 summarizes load impacts, by rebate type (purchase or recycling) and by year. Overall, these new rebates generated 25.2 kW in peak load reductions. The majority of these impacts comes from recycling inefficient window AC units without replacing them with a new unit. Savings from the purchase of new efficient window AC units or the recycling of inefficient units with replacement, on the other hand, generated relatively small savings.

Table 5-1 Ex-post Gross Peak Load Impacts for Recycled and Rebated Window AC Units: 2013-2017 (kW)

Measure	2013	2014	2015	2016	2017	Cumulative
Window AC Purchase	0.8	0.2	0.2	0.3	0.1	1.6
Window AC Recycling	6.1	6.5	2.4	5.4	3.2	23.6
Recycled WAC (no replacement)	5.0	6.2	2.2	5.2	3.0	21.7
`Recycled WAC (with replacement)	1.0	0.3	0.2	0.2	0.2	1.9
Total Window AC	**6.9**	**6.7**	**2.6**	**5.8**	**3.3**	**25.2**

Source: Program Tracking Data; PY2017 Gross Impact Analysis

5.1.3 Window AC Rebate Key Process Findings

The annual evaluations did not include process work specific to the window AC rebates. However, the 2017 general population survey explored awareness of and interest in the rebates among customers who had window AC units or were planning to use them during the summer.

- A majority of non-participants were unaware of the available rebates for purchasing new efficient window AC units (57%) and recycling old inefficient units (71%).
- More than half of window AC rebate and window AC recycling leads (57%) reported first hearing about the rebates through direct mailings from National Grid; another 19% first heard about the rebates through a phone call from National Grid. Only two out of 21 leads (10%) first heard about the window AC offering through an EnergyWise audit.
- The potential customer base eligible to receive a rebate for purchasing a new window AC unit was quite large: Almost 4 out of 10 customers (39%) used or planned to use window AC to cool their home in the summer, and 35% of those window AC users (or 14% of all customers) were likely[19] to purchase a new window AC unit in 2017. A large majority of these likely buyers (93%) reported that they were likely to purchase an ENERGY STAR® rated model and apply for a rebate from National Grid.[20] In contrast to the large pool of potential participants, the number of actual 2017 participants was quite small (10). While a self-reported likelihood to take energy efficient actions always has to

[18] For details on the methodology and the resulting per unit values, see the 2014 Annual Evaluation Report, dated August 10th, 2015, developed by Opinion Dynamics.

[19] A rating of 3 or greater on a 5-point scale, where 1 means "not at all likely" and 5 means "very likely".

[20] Based on a population of 4,756 unique residential substation customers, these percentages translate into 1,874 customers who use window AC, 656 customers likely to purchase a new unit in 2017, and 609 customers likely to apply for a rebate.

be interpreted with caution, awareness of the rebate appears to be a major barrier: only 38% of eligible customers likely to apply for a rebate, were aware of the rebate before taking the survey. For future efforts, to better promote offers like the window AC rebates, National Grid should consider more focused messaging, e.g., in combination with a time-limited enhanced rebate, or an “event” like Window AC Recycling Month, which can be effective in promoting action by potential participants.

- Only 19% of customers had window AC units that they no longer used or that they were thinking about replacing in 2017.

6. Conclusions and Recommendations

Estimated cumulative peak demand savings for the pilot period are 316 kW, less than a third of the pilot's 1 MW goal. While the pilot did not meet its goal, its initial progress postponed the investment of the wires alternative that would have occurred in 2014 if not earlier. The investment in the substation upgrade was further deferred due to slower than expected load growth and cooler summer temperatures in 2017. Two key factors contributed to the pilot falling short of its goal:

- **Lower than expected savings from the DemandLink Thermostat Program:** Residential demand response events achieved only 40 kW in 2017, compared to a target of 455 kW.[21] Low incidence of central AC among pilot area residents, challenges with thermostat and plug device connectivity, and a conservative event strategy were largely responsible for the residential shortfalls. In addition, the pilot had a target of 134 kW for commercial demand response events but never rolled out a commercial DemandLink program.

- **Limited savings from SRP-specific energy efficiency offerings:** National Grid had set an aggressive load reduction target of 685 kW for SRP-specific energy efficiency offerings. However, National Grid only introduced two SRP-specific energy efficiency measures (rebates for new energy efficient window AC units and for window AC recycling), which only achieved a combined 25 kW due to limited uptake.

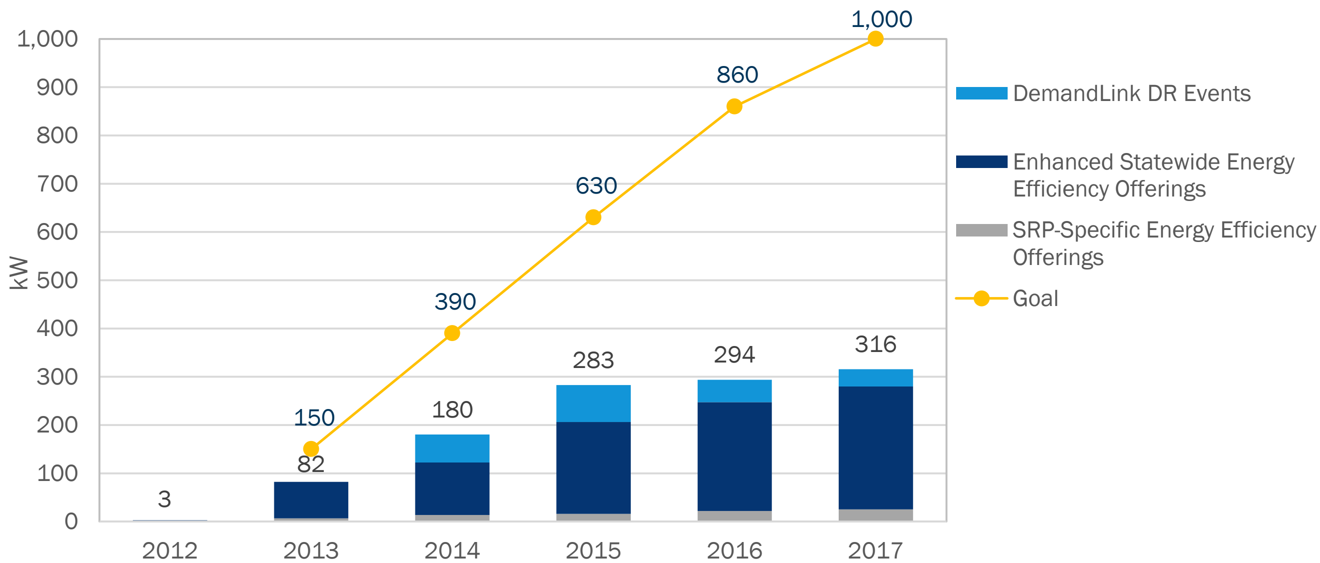
Compared to the other two components, impacts from the enhanced statewide energy efficiency offerings (255 kW) were much closer to target (320 kW). The pilot might have met this target, had it not been for two factors: (1) Lighting measures accounted for the vast majority of the savings in the EnergyWise Program. The changing baseline for residential lighting measures due to new EISA standards means that savings from these measures have been decreasing over time. (2) The pilot deemphasized the commercial sector after an initial push in 2013. As a result, savings from the SBDI Program between 2014 and 2017 were small.

Because peak demand on feeders 33 and 34 is still high, National Grid decided in 2017 to issue an RFP for a battery storage solution. Battery power will be used to meet the remaining excess demand during peak load times, meaning that substation upgrades can be further deferred.

Figure 6-1 shows the pilot's cumulative load impacts compared to the cumulative reduction National Grid expected to need to defer substation upgrades.

[21] The total cumulative kW reduction target, was greater than 1 MW to allow for some loss of impacts due to DemandLink participants opting out of demand response events.

Figure 6-1. Cumulative Load Impacts (kW) Compared to Goal



Source: PY2012-2017 Gross Impact Analyses

For future similar non-wires alternatives, National Grid should consider the following recommendations:

Table 6-1. Recommendations for Future Non-wires Alternatives

Recommendation	Explanation
Demand Response Offerings	
Do not base a demand response program on equipment that, by definition, will be removed each year.	The approach of offering plug devices to enable customers with window AC to participate in the program was plagued with technical issues such as low connectivity, leading to few event participants and near-zero savings by 2016.
Keep a close eye on connectivity issues and ask for more accountability from the event implementer.	The high incidence of missing log files and log files with no data severely limited the load impacts realized by the program. While connectivity issues were not too surprising for customers with window AC, the high incidence of missing data for customers with central AC, especially in the final years of the pilot, was unusual. While National Grid did some investigations of the issue with Ecobee, the source of the problem was never fully diagnosed.
Consider using a cycling strategy, which would avoid the decrease in savings in later event hours, or a more aggressive offset strategy, e.g., of 3 or 4°F, which would reduce the decrease in savings.	The program chose a 2°F offset strategy for customers with central AC, fearing that a cycling strategy or a higher offset would lead to participant dissatisfaction. However, small temperature offsets are subject to decreasing load impacts in later event hours, as the room temperature more quickly reaches the new setpoint.

Recommendation	Explanation
Keep the 3-hour event length and ensure that events start as closely to the predicted peak demand as possible.	The switch from 4-hour to 3-hour events, helped avoid the near-zero savings observed in the last hour of prior events and resulted in the highest average hourly per thermostat savings across the four event seasons. Starting the event as close as possible to the predicted peak ensures that the higher first-hour savings are realized during the times of highest demand.
Consider adding a pre-cooling period.	The SRP event strategy did not include pre-cooling. Precooling is an effective approach for both offset and cycling strategies as it delays the room temperature reaching the new setpoint, thereby further reducing event time usage.
Call events at times of predicted peak demand, rather than using trigger conditions, which may not well correlate with peak demand.	In 2017, National Grid called events when daytime temperatures, nighttime temperatures, or humidity forecasts met certain trigger conditions. This strategy resulted in one-third of events being called when event time temperatures were very moderate (between 69 to 73°F); these events tended to have lower savings than events with higher event time temperatures. Calling events during moderate temperature conditions is justified if the demand reduction is needed at that time (based on load forecasts). If it is not needed, then these events will result in lower average event savings for the program.
Energy Efficiency Offerings	
Continue to leverage established programs, such as EnergyWise or SBDI.	The enhanced statewide energy efficiency offerings were the most successful part of the pilot. EnergyWise is an established program that enjoys high levels of customer awareness and popularity and can serve as a channel into other offerings.
Diversify away from lighting.	Lighting measures accounted for the vast majority of EnergyWise savings, initially in the form of CFLs (2012-2013) and later in the form of LEDs (2014-2017). While these measures contributed significantly to deferring substation upgrades in the early years of the pilot, the changing baseline for residential lighting measures (due to new EISA standards) resulted in decreasing savings from these measures over time. Earlier diversification away from lighting might have mitigated the loss in savings in the final years of the pilot.
Pursue opportunities in all sectors.	The pilot discontinued small business outreach efforts after 2013, despite a substantial increase in SBDI program participation. Considering that the SBDI Program achieved over 50% of its 5-year participation in 2013—and accounted for almost one-third of cumulative pilot load impacts—the pilot may have missed an opportunity for additional savings, by not continuing outreach to this sector.

Recommendation	Explanation
Marketing Strategy	
Ensure that community benefits are a central and visible theme of outreach messaging for future community-focused efforts.	A community benefits theme is generally effective in motivating additional groups of customers. Focus group participants expressed a desire for more transparent messaging around the demand response events and why National Grid had targeted Tiverton and Little Compton for the offering. The societal and community benefits of the program, including lower greenhouse gas emissions and improved grid reliability, were thought to be potential drivers of participation for customers who are not motivated by free equipment or bill savings. While National Grid began including a "Good for you, good for your community" theme in its messaging in 2014, it was often combined with other offers and messaging and therefore likely not sufficiently visible to the target audience.
Consider more focused messaging to better promote pilot-specific offerings.	The window AC recycling rebate had the lowest awareness among all program offerings. Messaging for this rebate was generally combined with information about other offerings and might therefore not have received much notice by customers. Yet, these rebates accounted for 7% of pilot load impacts. For future efforts, to better promote offers like the window AC recycling rebate, National Grid should consider more focused messaging, e.g., in combination with a time-limited enhanced rebate, or an "event" like *Window AC Recycling Month*, which can be effective in promoting action by potential participants.

7. References

The following evaluation deliverables form the basis for this report:

- Opinion Dynamics Corporation, 2018. Central Air Conditioning Demand Response Event Analysis. Memorandum dated April 6, 2018.
- Opinion Dynamics Corporation, 2017. National Grid Rhode Island System Reliability Procurement Pilot: 2016 Annual Evaluation Report. Report dated June 6, 2017.
- Opinion Dynamics Corporation, 2016. National Grid Rhode Island System Reliability Procurement Pilot: 2015 Annual Evaluation Report. Report dated August 3, 2016.
- Opinion Dynamics Corporation, 2015. 2014 Annual Evaluation Report. Report dated August 10, 2015.
- Opinion Dynamics Corporation, 2014a. National Grid Rhode Island System Reliability Procurement Pilot: 2013 Marketing Effectiveness Findings. Report dated April 24, 2014.
- Opinion Dynamics Corporation, 2014b. National Grid Rhode Island System Reliability Procurement Pilot: 2012-2013 Focused Energy Efficiency Impact Evaluation. Report dated May 12, 2014.
- Opinion Dynamics Corporation, 2013. National Grid Rhode Island System Reliability Procurement Pilot: 2012 Marketing Effectiveness Findings. Memorandum dated March 29, 2013.

Other references include:

- U.S. Census Bureau. American Community Survey. 2012 – 2016 American Community Survey 5 – Year Estimates. *DP04: Selected Housing Characteristics.* Retrieved January 2016. from factfinder.census.gov.
- U.S. Census Bureau. American Community Survey. 2010 – 2014 American Community Survey 5 – Year Estimates. *DP04: Selected Housing Characteristics.* Retrieved April 2014, from factfinder.census.gov.
- U.S. Census Bureau. American Community Survey. 2008 – 2012 American Community Survey 5 – Year Estimates. *DP04: Selected Housing Characteristics.* Retrieved April 2013, from factfinder.census.gov.
- U.S. Census Bureau. Business Patterns. 2013 Business Patterns. *CB1300CZ21: ZIP Code Business Statistics: Zip Code Business Patterns by Employment Size Class.* Retrieved January 2016, from factfinder.census.gov.

Appendix A. Summary of Evaluation Activities

The following table summarizes the evaluation activities and key deliverables completed for each year of the SRP pilot.

Table A-1. Summary of Evaluation Activities and Key Deliverables, by Program Year

PY	Primary Data Collection	Process Evaluation	Impact Evaluation
2012/ 2013	▪ EnergyWise Participant Survey (Online: May 2013, Oct. 2013, Mar. 2014) ▪ Residential Non-Participant Focus Groups (Nov. 2013)	▪ Data tracking review ▪ 2012 Marketing effectiveness analysis (residential and commercial) ▪ 2013 Marketing effectiveness analysis (residential)	▪ EnergyWise gross and incremental load impacts
	Key Deliverables: ▪ 2012 Marketing Effectiveness Findings. Memorandum dated March 29, 2013. ▪ National Grid Rhode Island System Reliability Procurement Pilot: 2013 Marketing Effectiveness Findings. Report dated April 24, 2014. ▪ 2012-2013 Focused Energy Efficiency Impact Evaluation. Report dated May 12, 2014.		
2014	▪ EnergyWise Participant Survey (Online: Dec. 2014) ▪ DemandLink Participant Survey (Telephone: June 2014, Oct. 2014) ▪ Residential Leads Survey (Telephone: Mar. 2015)	▪ 2014 Marketing effectiveness analysis ▪ Residential leads analysis ▪ DemandLink process analysis (awareness/perceptions, satisfaction, participation in DR events)	▪ EnergyWise gross and incremental load impacts ▪ Window AC rebate and recycling gross impacts ▪ DR event impacts (CAC and WAC) ▪ Potential for efficiency impacts (WiFi Thermostats, Plug Devices)
	Key Deliverables: ▪ 2014 Annual Evaluation Report. Report dated August 10, 2015.		
2015	▪ EnergyWise Participant Survey (Online: Jan. 2016) ▪ DemandLink Participant Survey (Telephone: Dec. 2014) ▪ Residential Leads Survey (Telephone: Jan. 2016)	▪ DemandLink process analysis (awareness/perceptions, satisfaction, participation in DR events) ▪ Residential leads analysis	▪ EnergyWise gross and incremental load impacts ▪ SBDI gross and incremental load impacts ▪ Window AC rebate* and recycling* gross impacts ▪ DR event impacts (CAC and WAC)
	Key Deliverables: ▪ National Grid Rhode Island System Reliability Procurement Pilot: 2015 Annual Evaluation Report. Report dated August 3, 2016.		
2016	▪ General Population Survey (Online: Mar. 2017) ▪ DemandLink Event Follow-up Survey (Phone: Aug. 2016)	▪ 2016 Marketing effectiveness analysis (awareness, interest, barriers) ▪ 2016 DR event follow-up analysis	▪ EnergyWise gross and incremental* load impacts ▪ DR event impacts (CAC and WAC*)
	Key Deliverables: ▪ National Grid Rhode Island System Reliability Procurement Pilot: 2015 Annual Evaluation Report. Report dated August 3, 2016.		
2017	▪ EnergyWise Participant Survey (Online: Dec. 2017)	▪ No process evaluation	▪ EnergyWise gross and incremental load impacts ▪ SBDI gross and incremental load impacts

PY	Primary Data Collection	Process Evaluation	Impact Evaluation
			▪ Window AC rebate* and recycling* gross impacts ▪ DR event impacts (CAC)
	Key Deliverables: ▪ Central Air Conditioning Demand Response Event Analysis. Memorandum dated April 6th, 2018. ▪ National Grid Rhode Island System Reliability Procurement Pilot: 2012-2017 Summary Report. Report dated July 25, 2018.		

* Using per unit impact values from a prior evaluation.

Appendix B. EnergyWise Gross Impacts

Table B-1 presents the measure counts and load impacts for all EnergyWise measures. The cumulative measure quantity is equal to the sum of installations throughout the pilot period. The cumulative peak load reduction, however, excludes savings from measures in the early years, once the measures have reached the end of their useful life. Savings excluded because of the measures' end of useful life include torchieres installed in 2012 and 2013 (with an expected useful life of 4 years) as well as 2012 smart strips and refrigerator brush measures (with an expected useful life of 5 years).

Table B-1. EnergyWise Installed Measures and Ex Ante Gross Peak Load Reduction: March 2012-2017

Measure Category	Total Measure Quantity							Total Peak Load Reduction (kW)						
	2012[a]	2013	2014	2015	2016	2017	Cumulative	2012[a]	2013	2014	2015	2016	2017	Cumulative
LED Bulb	87	998	3,946	10,973	5,060	3,952	25,016	0.5	5.3	21.0	58.5	27.0	21.1	133.3
CFL	2,382	8,670	1,867	233	47	0	13,199	1.9	6.8	1.5	0.2	<0.1	-	10.3
Indoor Fixture	24	95	25	13	18	29	204	<0.1	0.1	<0.1	<0.1	<0.1	<0.1	0.2
Torchiere[c]	4	1	0	2	0	0	7	<0.1	<0.1	-	<0.1	-	-	0.0
Outdoor Fixture	1	11	26	19	31	34	122	-	-	-	-	-	-	-
Smart Strip[c]	60	539	363	568	347	232	2,109	0.2	1.6	1.1	1.7	1.0	0.7	6.0
Refrigerator Brush[c]	103	297	191	253	158	111	1,113	0.1	0.3	0.2	0.3	0.2	0.1	1.0
Refrigerator Rebate	3	6	5	4	2	0	20	0.1	0.2	0.1	0.1	0.1	<0.1	0.5
Programmable Thermostat (all fuels)	5	41	18	32	25	4	125	<0.1	0.1	0.1	0.1	0.1	<0.1	0.3
Weatherization (all fuels)[b]	0	31	27	25	11	25	119	-	-	-	-	-	-	-
Ventilation – Other[b]	0	28	23	19	5	13	88	-	-	-	-	-	-	-
AC Timer	0	0	1	0	0	0	1	-	-	-	-	-	-	-
Aerator	0	65	0	0	3	12	80	-	0.4	-	-	<0.1	0.1	0.5
HPWH 50 Gallon	0	1	0	0	0	0	1	-	0.2	-	-	-	-	0.2
DHW Pipe Wrap/Insulation	0	3	12	21	0	0	36	-	-	-	<0.1	-	-	0.0
Low Flow Showerhead	0	3	3	7	0	4	17	-	<0.1	<0.1	<0.1	-	<0.1	0.1
TOTAL	2,669	10,789	6,507	12,169	5,707	4,416	42,257	2.7	14.9	24.0	60.8	28.3	22.0	152.4

[a] The 2012 participation period is between 3/1/2012 and 12/31/2012.

[b] Quantities of Ventilation and Weatherization are the accounts of unique participants. All other quantities are measure counts (e.g., count of installed bulbs).

[c] Measures that have reached the end of their useful life are excluded from the cumulative peak load reduction estimate. They include torchieres installed in 2012 and 2013 (expected useful life = 4 years) as well as 2012 smart strips and refrigerator brush measures (expected useful life = 5 years).

Appendix C. EnergyWise Net Impacts

To estimate net impacts for the EnergyWise Program, we developed a “take rate,” which represents the proportion of pilot area installations that are attributable to the SRP pilot. The take rate is based on two measures of attribution: (1) the incremental participation rate (see Section 4.1.1) and (2) an attribution rate developed based on responses to the EnergyWise participant survey.[22]

The estimated take rate for the SRP pilot is 47%, which is the mid-point between the incremental participation rate (48%) and the attribution rate from the EnergyWise surveys (46%). Applying the two rates to the measure-level results, we estimate that the pilot overall achieved net summer peak load savings totaling 71.5 kW, with a range of 69.6 kW to 73.3 kW.

Table C-1 presents the impact ranges for each EnergyWise measure category.

Table C-1. EnergyWise Incremental Load Impacts by Measure Category: March 2012-2017

Measure Category	Peak Load Reduction (kW)	
	Cumulative	Range
LED Bulbs	62.5	60.9 - 64.1
CFL	4.8	4.7 - 5.0
Indoor Fixtures	0.1	0.1 - 0.1
Torchiere	<0.1	<0.1 - <0.1
Outdoor Fixture	-	-
Smart Strip	2.8	2.7 – 2.9
Refrigerator Brush	0.5	0.5 - 0.5
Refrigerator Rebate	0.2	0.2 - 0.3
Programmable Thermostat	0.2	0.2 - 0.2
Weatherization (multiple fuels)	-	-
Ventilation – Other	-	-
AC Timer	-	-
Aerator	0.2	0.2 - 0.2
HPWH 50 Gallon	0.1	0.1 - 0.1
DHW Pipe Wrap/Insulation	<0.1	<0.1 - <0.1
Low Flow Showerhead	<0.1	<0.1 - <0.1
TOTAL	71.5	69.6 - 73.3

[22] For detailed discussion on incremental participation rate calculation methodology, see National Grid RI SRP 2015 Annual Evaluation Report, by Opinion Dynamics, dated August 3rd, 2016.

Appendix D. SBDI Gross Impacts

Table D-1 presents the measure counts and load impacts for all SBDI measures. The cumulative values are equal to the sum of measure quantities and kW load reduction, respectively, throughout the pilot period. In contrast to the EnergyWise Program, no SBDI measures installed during the pilot period had reached the end of their useful life by 2017.

Table D-1. SBDI Installed Measures and Ex Ante Gross Peak Load Reduction: August 2012-2017

Measure Category	Total Measure Quantity [a]						Total Peak Load Reduction (kW)					
	2013	2014	2015	2016	2017	Cumulative	2013	2014	2015	2016	2017	Cumulative
LED Bulb	982	12	305	90	152	1,541	44.2	0.9	8.7	4	6	63.6
CFL	320	89	10	-	-	419	12.7	3.2	0.7	-	-	16.6
Indoor Fixture	-	-	2	1	-	3	-	-	8.4	0.2	-	8.6
Torchiere	-	10	6	9	-	25	-	1.3	0.8	0.1	-	2.2
Outdoor Fixture	-	2	-	-	-	2	-	1.1	-	-	-	1.1
Smart Strip	4	9	-	-	-	13	0.2	0.6	-	-	-	0.8
Refrigerator Brush	22	5	-	-	-	27	0.6	0.0	-	-	-	0.6
Refrigerator Rebate	11	5	8	-	-	24	0.3	0.1	0.1	-	-	0.6
Programmable Thermostat (all fuels)	-	-	3	12	-	15	-	-	0.3	0.1	-	0.5
Weatherization (all fuels)[a]	-	7	-	-	-	7	-	0.7	-	-	-	0.7
Ventilation – Other[a]	-	3	-	-	-	3	-	0.4	-	-	-	0.4
AC Timer	-	3	-	-	-	3	-	0.2	-	-	-	0.2
Aerator	-	8	-	-	-	8	-	-	-	-	-	-
HPWH 50 Gallon	-	1	-	-	-	1	-	0.6	-	-	-	0.6
DHW Pipe Wrap/Insulation	4	-	-	-	-	4	-	-	-	-	-	-
Low Flow Showerhead	1	-	-	-	-	1	-	-	-	-	-	-
TOTAL	1,344	154	334	112	152	2,096	57.9	9.2	19.0	4.4	5.9	96.4

[a] Quantity and savings by year are based on installation date and include projects with audits after 8/15/2012 and invoice dates through 12/31/2017.

Appendix E. SBDI Net Impacts

To estimate net impacts for the SBDI Program, we applied the evaluated incremental participation rate of 40% (see Section 4.2.1) to ex ante gross savings, by measure category. We estimate that the pilot overall achieved net summer peak load savings totaling 38.4 kW.

Table E-1 presents the incremental impacts for each measure category.

Table E-1. SBDI Incremental Load Impacts by Measure Category: August 2012-2017

Measure Category	Incremental Peak Load Reduction (kW)
LED Bulbs	25.3
Linear Fluorescent Lighting	6.6
Custom Lighting	3.4
HID Lighting	0.9
Custom Refrigerator Lighting	0.4
LED Refrigerated Case Lighting	0.3
Occupancy Sensors	0.2
LED Exit Signs	0.2
CFLs	0.2
Non-HVAC Motors/Drives	0.3
Fan Control	0.2
Door Heater Control	0.1
Novelty Cooler Shutoff	-
Custom Motors/Drives	0.2
Vending Machines	-
Custom Hot Water	-
TOTAL	38.4

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Appendix 4 – Projects Screened for NWA

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
1	C078460	Reconductor 3308 Substation transmission Line	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/18/2017
2	C078474	Franklin Square Substation Network Feeders	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/23/2017
3	C078476	Hope Substation Pole Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/23/2017
4	C078488	RI DFP100 Protective Relay Replacement Project	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		5/25/2017
5	C078596	RI 33F4 Feeder - Reconductor existing small wire with 477 spacer cable	A NWA project would not be suitable as a replacement for the wires solution. Upon further evaluation, there is no reduction in load that would resolve the tree conditions and intermittent loss of power issues to a large number of customers.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Reliability		6/15/2017
6	C078686	RI 32J12 Feeder - Ella Terrace URD Cable Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		6/28/2017
7	C078693	RI 18F13 Feeder - URD High Ridge Condominiums Cable Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		6/29/2017
8	C078695	RI 21F2 Feeder - URD Alpine Estates Cable Cure Project	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		6/29/2017
9	C078720	RI 37W42 Feeder - URD East Bay Village Apartments Cable Cure Project	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement - I&M (NE)		7/3/2017

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
10	C078734	Providence Study: Admiral St 4kV & 11kV Conversion	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/5/2017
11	C078735	Providence Study: New Admiral St 12kV Distribution Substation	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/6/2017
12	C078796	Providence Study Admiral St-Rochamb Substation Distribution Line	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
13	C078797	Providence Study Admiral St-Rochamb Distribution Substation	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
14	C078800	Providence Study Clarkson St & Lippitt Hill 12kV Distribution Line	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
15	C078801	Providence Study Admiral St Demolition	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
16	C078802	Providence Study Olneyville 4kV Distribution Line	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
17	C078803	Providence Study Admiral St 12kV Manhole & Duct System	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
18	C078804	Providence Study Admiral St 12kV Cables	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
19	C078805	Providence Study Knightsville 4kV Conversion	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
20	C078806	Providence Study Knightsville 4kV Distribution Substation	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
21	C078810	Providence Study Harris Ave 11kV (1129&1137)	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
22	C078811	Providence Study Geneva, Olneyville, Rochamb 4kV	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/14/2017
23	C078847	Providence Study Geneva 4kV Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
24	C078849	Providence Study Harris Ave Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
25	C078850	Providence Study Olneyville 4kV Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
26	C078851	Providence Study Rochambeau 4kV Substation Removal	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/18/2017
27	C078857	Providence Study Harris Ave 4kV & 11kV Retirement	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		7/19/2017
28	C078921	RI Underground Cable Replacement Program - Fdr 1158	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
29	C078923	RI Underground Cable Replacement Program - Fdr 1160	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
30	C078926	RI Underground Cable Replacement Program - Fdr 1162	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
31	C078928	RI Underground Cable Replacement Program - Fdr 1164	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
32	C078931	RI Underground Cable Replacement Program - Fdr 1166	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
33	C078933	RI Underground Cable Replacement Program - Fdr 1168	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement	UG Cable Replacements	7/31/2017
34	C079076	Narragansett Electric Distribution Substation PLC Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Reliability Driven Project	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	Substation		8/24/2017
35	C079183	RI Replacement of ACNW Vault Vent Blowers	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		9/15/2017
36	C079234	Mobile Substation ID# 5616 Refurbishment & Upgrade	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Substation		9/26/2017
37	C079282	RI VVO/CVR Exp - Washington 126 Distribution Line	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	Reliability		10/4/2017
38	C079288	RI VVO/CVR Expansion - Staples 112 Distribution Line	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	Reliability		10/4/2017
39	C079300	RI VVO/CVR Exp - Washington 126 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	Reliability		10/6/2017
40	C079317	Providence Study Harris Av & Olneyville Supply	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		10/9/2017
41	C079318	Providence Study Remove Rochambeau Supply	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Comprehensive Plan from Providence Area Study: Asset Condition Drive. See Study for Further Details	Asset Condition	Asset Replacement		10/9/2017

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Budget Classification	Program Code	Date Initiated
42	C079418	Tiverton 3V0 Distribution Substation	DOES NOT MEET NG 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	Reliability		10/30/2017
43	C079482	RI VVO/CVR Exp - Staples 112 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	Reliability		11/13/2017
44	C079493	Kilvert St T1 3V0 Distribution Substation	DOES NOT MEET NG 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	Reliability		11/15/2017
45	C079525	Old Baptist Rd 3V0 Distribution Substation	DOES NOT MEET NG 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	Reliability		11/16/2017
46	C079599	RI 155F4 Asset Replacement-Narragansett Way	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		12/4/2017
47	C080092	15F1 and 15F2 Getaway Relocation	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Asset Replacement		2/21/2018
48	C080231	Kent County ARP Breaker Replacement	DOES NOT MEET NG NWA SCREENING REQUIREMENTS - Asset Condition Driven Project, < $1M in cost	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	Substation		3/22/2018

Appendix 5 – Presentation of Update on Locational Incentive Analysis for RI OER and Division

Rhode Island Renewable Energy Growth Program

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Update on Locational Incentive Analysis for RI OER and Division
September 12, 2017

1

Overview

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- Project Findings Summary
- Feeder screening and peak analysis
- Three approaches to avoided-cost benefit
- Solar contribution to load reduction
- Examples of application as a locational incentive
- Temporal transmission benefits

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Project Findings Summary

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- Our research and analysis on locational incentives focused on 1) an expedited method for screening feeders; 2) understanding the benefits solar could provide; and 3) estimating a benefit value that provides the basis for a locational incentive.
- As initially discussed, our screening looked at feeders at least 80% loaded. However, none of the feeders that passed screening (except those in SRP Pilot) are forecast to be constrained within our planning horizon and criteria, so there is presently no cost to avoid
- As a result, the Company opts to defer further development of a Locational Incentive for this program year, but will reexamine the opportunity again in winter/spring with 2017 data, application of the BCA Framework, and any changes in forecasting, such as for beneficial electrification
- If forecasts point to constraints in the future, the rest of the presentation outlines how we could design and calculate a potential locational incentive

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Feeder Analysis Screening -- Review

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- Analysis of feeders and substations in Rhode Island based on loading, asset condition and expected growth provides a reasonable basis on which to consider a Locational Incentive within the RE Growth Program
- The analysis is not as detailed at the “Heat Map” results of system area studies, and leaves out sectional analysis and voltage issues, for example
- The criteria used in this analysis include:
  - Feeder must be at least 80% loaded in last year
  - Asset must not be scheduled for upgrade due to asset age or condition
  - Load on the asset must not be declining
  - The result of the analysis is a list of 25 feeders
- None of the feeders are predicted to reach 100% except those in the SRP area, and thus are not truly in need of deferral
- Of these feeders, 20 had hourly load data immediately available in a form ready to be analyzed

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Feeder Temporal Analysis Indicates Variation in Peaks -- Review

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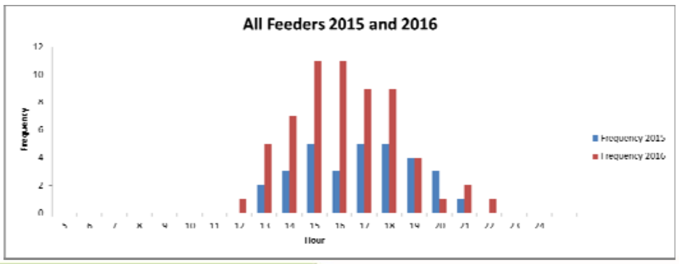
- Each feeder that passed the screening criteria was further analyzed for the times of its peak hours of loading
- The top 3% of hours by kVA on each feeder were sorted by hour for 2015 and 2016; other approaches are possible
- The resulting analysis shows that two groups of feeders peak at different times



Feeders Classified into Early and Late Peaking -- Review

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Hour	Feeder Group	12	13	14	15	16	17	18	19	20	21	22
72F3	Late					16	17	18				
72F6	Early		13	14	15	16						
27F2	Early				15	16	17					
27F4	Early		13	14	15							
63F6	Late							18	19	20		
100F1	Early			14	15	16						
76F1	Early			14	15	16	17					
76F2	Early		13	14	15	16	17	18				
76F4	Late				15			18	19	20	21	22
76F5	Early				15	16	17				21	
76F6	Early		13	14	15							
76F7	Early	12	13	14	15	16		18	19	20		
46F4	Late						17	18	19			
59F3	Late				15	16	17	18				
17F2	Late			14	15	16	17	18				
68F2	Late						17	18	19			
33F2	Late					16	17	18				
33F4	Late						17	18	19			

The time of peak significantly impacts the potential value that solar can provide to reduce loading, and thus the amount of incentive it might earn.

2015 only
2016 only
2015 and 2016

Three Approaches to Determining Potential Avoided Cost Benefits

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We examined three different approaches to estimate potential benefits from load relief, both broadly and at specific locations:

1. System-wide Avoided Transmission and Distribution Cost
2. Line-specific deferral value of distribution system upgrades as measured by the avoided revenue requirement NPV, multiplied by the probability of a spot load developing necessitating an upgrade
3. Time-value deferral NPV, similar to what has been used for the System Reliability Plan area.

Approach 1: Avoided Transmission and Distribution Cost

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- The Avoided Transmission and Distribution (T&D) Cost approach is a system wide approach that looks at historic and forecast summer peak impacts for T&D.
- The EE Avoided T&D Cost estimate shows the marginal cost of transmission and distribution capacity to be a combined $93.16/kW-year.
  - This assumes all growth dollars are truly capacity related versus service connection related - more work needs to be done to separate
- When expected EE and DG program impacts are included in the forecast, these forecast growth spend dollars are naturally spread over much fewer MWs of growth due to minimal load growth, resulting in $/kw-year values that don't make any sense.
- This approach does not provide useful measure of the locational specific cost of growth to be considered when looking at the post-EE, post-DG program forecast due to the granular nature of new service spending that we experience

Two Methods to Determine Feeder Deferral Costs

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- These 20 feeders are all heavily loaded, but not scheduled to be upgraded in the next three years, and do not appear to reach 100% in the next 10 years based on current load forecasting, except those in SRP pilot
- Whether a constraint suddenly appears, and its location, is uncertain. Roughly 1% of feeders require upgrades annually due to spot/pop-up loads.
- We employed two methods to estimate deferral values for this infrastructure:
  - Method 1: Probability-weighted Avoided Revenue Requirement NPV
    - Over a 10-year deferral period, this would provide a probability weighting of roughly 10% of the avoided RR NPV
  - Method 2: 10-year Deferral of Full Revenue Requirement
    - We calculate the difference in NPV between building an upgrade now, or a 10-year delay
- To relieve constraints, in some circumstances two or three mile segments of feeder must be replaced. Only a base case of 1-mile upgrades is presented here.

First Step: Determining Feeder Costs

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The location of future constraint is uncertain, so we develop a feeder-specific weighted average cost per mile

Four Inputs per Feeder:

- Miles of overhead per feeder (M_{0i})
- Miles of underground per feeder (M_{Ui})
- System average cost of overhead feeder per mile (C_0)
- System average cost of underground feeder per mile (C_U)

Feeder $Cost_i = (C_0 * M_{0i} + C_U * M_{Ui}) / (M_{0i} + M_{Ui})$

Feeder Avoided Cost Estimates

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Cost of Feeders		Method 1		Method 2	
Study Area	Feeder ID	10% Current Value		10-year Lag	
Central RI West	100F1	$	188,133	$	750,697
South County East	17F2	$	134,317	$	535,959
Central RI East	27F2	$	102,511	$	409,043
Central RI East	27F4	$	145,391	$	580,147
Central RI East	27F5	$	98,583	$	393,370
TIVERTON	33F2	$	126,440	$	504,528
TIVERTON	33F4	$	119,922	$	478,518
South County East	46F4	$	148,986	$	594,492
Central RI West	54F1	$	99,191	$	395,796
South County East	59F3	$	150,523	$	600,622
Central RI West	63F6	$	99,877	$	398,536
South County West	68F2	$	113,077	$	451,203
Central RI East	72F3	$	102,536	$	409,145
Central RI East	72F6	$	99,260	$	396,072
Providence	76F1	$	116,286	$	464,011
Providence	76F2	$	115,511	$	460,915
Providence	76F4	$	107,062	$	427,205
Providence	76F5	$	142,239	$	567,569
Providence	76F6	$	120,148	$	479,422
Providence	76F7	$	113,471	$	452,777

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Potential Approach to a Locational Incentive Structure

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- Constraint solutions would on average increase line capacity by 20%, based on past experience
  - One approach is to distribute the value over the kW value of such additional capacity
- Lump sum payments or annualized payments are possible
  - Lump sum more closely mimics installation costs
  - Annualized based on output in peak period better incentivizes actual performance
- Annual payments can be divided over the peak load windows – 480 summer hours – to create $/kWh value

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Example Incentive Value: Annual Payment Values per kW

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	Feeder ID	Method 1 ($/kW-Year)	Method 2 ($/kW-Year)
Central RI West	100F1	$21.48	$85.70
South County East	17F2	$18.40	$73.42
Central RI East	27F2	$11.02	$43.97
Central RI East	27F4	$19.72	$78.70
Central RI East	27F5	$10.60	$42.28
TIVERTON	33F2	$17.15	$68.44
TIVERTON	33F4	$14.55	$58.04
South County East	46F4	$17.01	$67.87
Central RI West	54F1	$12.37	$49.38
South County East	59F3	$16.18	$64.56
Central RI West	63F6	$10.74	$42.84
South County West	68F2	$12.91	$51.51
Central RI East	72F3	$11.02	$43.98
Central RI East	72F6	$10.75	$42.90
Providence	76F1	$16.58	$66.16
Providence	76F2	$13.19	$52.62
Providence	76F4	$12.22	$48.77
Providence	76F5	$17.43	$69.57
Providence	76F6	$13.72	$54.73
Providence	76F7	$12.95	$51.69
	Average	$14.50	$57.85

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Transforming Annual Payments into $/kWh values

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Study Area	Feeder ID	Method 1 ($/kWh in 480 Peak Hours)	Method 2 ($/kWh in Peak)
Central RI West	100F1	$0.045	$0.179
South County East	17F2	$0.038	$0.153
Central RI East	27F2	$0.023	$0.092
Central RI East	27F4	$0.041	$0.164
Central RI East	27F5	$0.022	$0.088
TIVERTON	33F2	$0.036	$0.143
TIVERTON	33F4	$0.030	$0.121
South County East	46F4	$0.035	$0.141
Central RI West	54F1	$0.026	$0.103
South County East	59F3	$0.034	$0.134
Central RI West	63F6	$0.022	$0.089
South County West	68F2	$0.027	$0.107
Central RI East	72F3	$0.023	$0.092
Central RI East	72F6	$0.022	$0.089
Providence	76F1	$0.035	$0.138
Providence	76F2	$0.027	$0.110
Providence	76F4	$0.025	$0.102
Providence	76F5	$0.036	$0.145
Providence	76F6	$0.029	$0.114
Providence	76F7	$0.027	$0.108
	Average	$0.030	$0.121

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Example Incentive Payment: Lump Sum Value per kW provided

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Lump Sum	Feeder ID	Method 1 ($/kW)	Method 2 ($/kW)
Central RI West	100F1	$ 123.26	$ 491.83
South County East	17F2	$ 105.60	$ 421.37
Central RI East	27F2	$ 63.24	$ 252.32
Central RI East	27F4	$ 113.20	$ 451.68
Central RI East	27F5	$ 60.81	$ 242.66
TIVERTON	33F2	$ 98.44	$ 392.81
TIVERTON	33F4	$ 83.48	$ 333.10
South County East	46F4	$ 97.61	$ 389.49
Central RI West	54F1	$ 71.02	$ 283.39
South County East	59F3	$ 92.85	$ 370.50
Central RI West	63F6	$ 61.61	$ 245.84
South County West	68F2	$ 74.08	$ 295.61
Central RI East	72F3	$ 63.25	$ 252.39
Central RI East	72F6	$ 61.70	$ 246.22
Providence	76F1	$ 95.16	$ 379.70
Providence	76F2	$ 75.68	$ 301.98
Providence	76F4	$ 70.14	$ 279.89
Providence	76F5	$ 100.06	$ 399.25
Providence	76F6	$ 78.72	$ 314.10
Providence	76F7	$ 74.34	$ 296.64
	Average	83.21	332.04

For smaller projects without interval meters (<25 kW) a lump sum payment method could be calculated. This is per kW of PEAK production. Actual incentives would be scaled by predicted system production over peak. In the case of an early-peaking feeder, for a west-facing system, the DCP would be 42%.

Thus, a 6 kW system on Feeder 100FI under Method 2 would receive:

6 kW * 42% (peak/installed) * $491.83 / peak = $1,239.41
Or $206.57 per kW installed

Method 1:
$51.77 $/kW installed
$310.62 for a 6-kW system

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How much solar energy to procure to meet an 80% loading goal?

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- 80% is an artificial limit that is more conservative than the 100% now used for planning
- Three relevant factors:
  - Max loading of line in base year (2020)
  - Size of line
  - Goal line – we used 80% of line capacity to illustrate

Feeder ID	Line Capacity	Goal Line Capacity	2020 Usage	kW to Reach 80%
100F1	7632	6105.31	6685	579
17F2	6360	5087.76	5897	809
27F2	8106	6484.40	6615	130
27F4	6422	5137.64	5811	673
27F5	8106	6484.40	7304	820
33F2	6422	5137.64	6049	911
33F4	7183	5746.18	6991	1245
46F4	7632	6105.31	7044	939
54F1	6983	5586.56	5609	22
59F3	8106	6484.40	6538	54
63F6	8106	6484.40	6722	237
68F2	7632	6105.31	6251	146
72F3	8106	6484.40	7173	688
72F6	8043	6434.52	6554	120
76F1	6110	4888.24	5706	818
76F2	7632	6105.31	7603	1497
76F4	7632	6105.31	7252	1147
76F5	7108	5686.32	6697	1011
76F6	7632	6105.31	7227	1122
76F7	7632	6105.31	6887	781
			Total	13749

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"Distribution Contribution Percentage" – DCP: the capacity factor for solar systems over peak period

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- Summer Capacity Factor for 480 peak hours in two separate summer peaking groups (Group A 1-4:59pm, Group B 4-7:59pm)
- The total period capacity factor is the DCP

Summer Capacity Factor for South Facing 180 azimuth

Time	June	July	August	Sept.	Summer Capacity
Group A 1-4:59 pm	37.24%	40.45%	38.29%	28.32%	36.07%
Group B 4-7:59 pm	7.82%	8.83%	6.56%	3.25%	6.62%

Summer Capacity Factor for West Facing 270 azimuth

Time	June	July	August	Sept.	Summer Capacity
Group A 1-4:59 pm	43.4%	48.8%	44.2%	31.8%	42.1%
Group B 4-7:59 pm	13.3%	16.2%	11.8%	5.7%	11.7%

Consideration of Lost Revenue for West Facing Systems

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- South facing systems produce more total energy. However, west facing systems produce more energy late in the afternoon, more closely aligned with peak system, when it can have added value.
- If a system is west facing, how much revenue is lost compared to the traditional south-facing design? And how do these compare with the Deferral Value methodologies?
- Trackers generate more kWhs per year than fixed systems and provide west facing benefits. These systems may be beneficial to meeting both of these needs. This has been shown in the Tiverton demo. However, we do not model trackers in this analysis.
- Lost revenue by azimuth and system size (RE Growth Class) is shown on the next page.

Lost Revenue by Azimuth and by System Size

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Azimuth South vs Southwest	**180 vs 210**	
Difference in Total Annual Output by Azimuth (kWh)	**30,033.24**	
South vs Southwest Lost Revenue by Energy Class	**Lost $/MW/yr**	**Lost $/kW/yr**
Small-Scale Solar I- Host Owned (1-10 kW)	$ (9,265.25)	$ (9.27)
Medium-Scale Solar (26-250 kW DC)	$ (6,832.56)	$ (6.83)
Commercial-Scale Solar (251-999 kW DC)	$ (5,631.23)	$ (5.63)
Large-Scale Solar (1,000- 5,000 kW DC)	$ (4,520.00)	$ (4.52)
CRDG (Community Remote DG) Solar (251-999 kW DC)	$ (6,201.86)	$ (6.20)
CRDG Large Solar (1,000- 5,000 kW DC)	$ (5,060.60)	$ (5.06)
Azimuth South vs Southwest	**180 vs 240**	
Difference in Total Annual Output by Azimuth (kWh)	**104,697.22**	
South vs Southwest Lost Revenue by Energy Class	**Lost $/MW/yr**	**Lost $/kW/yr**
Small-Scale Solar I- Host Owned (1-10 kW)	$ (32,299.09)	$ (32.30)
Medium-Scale Solar (26-250 kW DC)	$ (23,818.62)	$ (23.82)
Commercial-Scale Solar (251-999 kW DC)	$ (19,630.73)	$ (19.63)
Large-Scale Solar (1,000- 5,000 kW DC)	$ (15,756.93)	$ (15.76)
CRDG (Community Remote DG) Solar (251-999 kW DC)	$ (21,619.98)	$ (21.62)
CRDG Large Solar (1,000- 5,000 kW DC)	$ (17,641.48)	$ (17.64)
Azimuth South vs West	**180 vs 270**	
Difference in Total Annual Output by Azimuth (kWh)	**206,447.79**	
South vs West Lost Revenue by Energy Class	**Lost $/MW/yr**	**Lost $/kW/yr**
Small-Scale Solar I- Host Owned (1-10 kW)	$ (63,689.14)	$ (63.69)
Medium-Scale Solar (26-250 kW DC)	$ (46,966.87)	$ (46.97)
Commercial-Scale Solar (251-999 kW DC)	$ (38,708.96)	$ (38.71)
Large-Scale Solar (1,000- 5,000 kW DC)	$ (31,070.39)	$ (31.07)
CRDG (Community Remote DG) Solar (251-999 kW DC)	$ (42,631.47)	$ (42.63)
CRDG Large Solar (1,000- 5,000 kW DC)	$ (34,786.45)	$ (34.79)

Values calculated from the RE Growth Ceiling Prices

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Translating Annual Value into Hourly Values

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By taking a “payment” of the $/kw-year value of deferral and translating into a $/kwh adder during a feeder’s peak hours, systems that generate more in that time window will gain more.

Annual Payment Value / 480 hours in peak window = $/kWh

Adder $/kWh * Actual output in peak = Annual Added Incentive

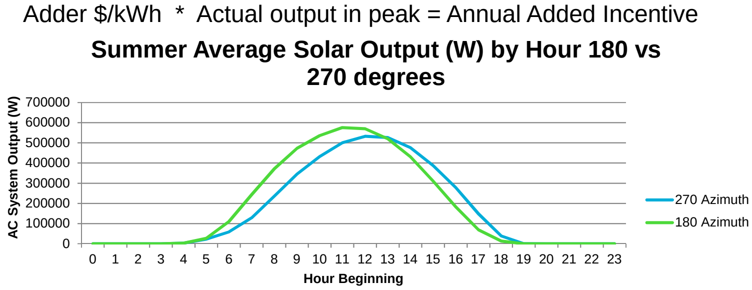

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Illustration of a Program Tariff Structure

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- Use Method 2 to determine the NPV of a 10-year deferral of an upgrade
- Divide this value over the 20% of avoided increase in average line capacity for a $/kW value
- For small (< or = 25 kW) systems, multiply the $/kW by a sharing factor, like 50%, to determine a lump benefit value
- For large systems, use an annual 10-year payment value to determine a $/kWh rate
  - Divide the $/kW annual value by 480 hours
  - Pay that amount $/kWh for each kWh produced to systems enrolled for a set period of time, e.g. five years
- Using lost revenue estimates, in some cases these values would be higher than losses, but in others there would be no incentive to point more westerly

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Method 2 Adders do not make up lost base revenue for small systems

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- Sample Early Peaking Feeder – 100F1

Group A	Lump Sum Benefit ($/kW Peak)	DCP	Value of Adder ($/kW INSTALLED)	Annual Value of Lump Payment	Annual Base Value ($/kW)	Total ($/kW)
South Facing (180)	$ 245.92	36%	$ **88.71**	$15.44	410.89	**$426.34**
South by SW (210)	$ 245.92	40%	$ **98.25**	$17.11	401.63	**$418.73**
West by SW (240)	$ 245.92	42%	$ **103.18**	$17.96	378.59	**$396.56**
West Facing (270)	$ 245.92	42%	$ **103.41**	$18.00	347.20	**$365.21**

- Sample Late Peaking Feeder – 46F4

Group B	Lump Sum Benefit ($/kW Peak)	DCP	Value of Adder ($/kW INSTALLED)	Annual Value of Lump Payment	Annual Base Value ($/kW)	Total ($/kW)
South Facing (180)	$ 194.75	7%	$ **12.88**	$ 2.24	410.89	$ **413.14**
South by SW (210)	$ 194.75	9%	$ **17.33**	$ 3.02	401.63	$ **404.64**
West by SW (240)	$ 194.75	11%	$ **20.93**	$ 3.64	378.59	$ **382.24**
West Facing (270)	$ 194.75	12%	$ **22.83**	$ 3.98	347.20	$ **351.18**

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For Large Systems, Method 2 incentive would *almost* be large enough to justify 210 orientations

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- Large Scale – Early Feeder – 100F1

Group A	Peak Period incentive ($/kWh)	Peak Output (kWh over peak period/kW)	Annual Value of Adder ($/kW)	Annual Base Value ($/kW)	Total ($/kW)
South Facing (180)	$ 0.18	173	$ 30.91	200.45	231.37
South by SW (210)	$ 0.18	192	$ 34.24	195.93	230.17
West by SW (240)	$ 0.18	201	$ 35.96	184.69	220.65
West Facing (270)	$ 0.18	202	$ 36.04	169.38	205.42

- Large Scale – Late Feeder – 46F4

Group B	Peak Period incentive ($/kWh)	Peak Output (kWh over peak period/kW)	Annual Value of Adder ($/kW)	Annual Base Value ($/kW)	Total ($/kW)
South Facing (180)	$ 0.14	32	$ 4.49	200.45	204.94
South by SW (210)	$ 0.14	43	$ 6.04	195.93	201.97
West by SW (240)	$ 0.14	52	$ 7.29	184.69	191.99
West Facing (270)	$ 0.14	56	$ 7.96	169.38	177.34

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For large systems, Method 1 is still *close* to making up for lost revenue at 210 degrees

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- Large Scale – Early Feeder – 100F1

Group A	Peak Period incentive ($/kWh)	Peak Output (kWh over peak period/kW)	Annual Value of Adder ($/kW)	Annual Base Value ($/kW)	Total ($/kW)
South Facing (180)	$ 0.045	173	$ 7.75	200.45	208.20
South by SW (210)	$ 0.045	192	$ 8.58	195.93	204.51
West by SW (240)	$ 0.045	201	$ 9.01	184.69	193.71
West Facing (270)	$ 0.045	202	$ 9.03	169.38	178.41

- Large Scale – Late Feeder – 46F4

Group B	Peak Period incentive ($/kWh)	Peak Output (kWh over peak period/kW)	Annual Value of Adder ($/kW)	Annual Base Value ($/kW)	Total ($/kW)
South Facing (180)	$ 0.035	32	$ 1.13	200.45	201.58
South by SW (210)	$ 0.035	43	$ 1.51	195.93	197.44
West by SW (240)	$ 0.035	52	$ 1.83	184.69	186.52
West Facing (270)	$ 0.035	56	$ 1.99	169.38	171.38

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Relative Compensation is closer to breakeven for Method 2

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- Total annual revenue by degree for selected feeders as percentage of 180º oriented systems

	100F1 - Early		46F4 - Late	
	Method 1	Method 2	Method 1	Method 2
South by SW (210)	98.2%	99.5%	98.0%	98.6%
West by SW (240)	93.0%	95.4%	92.5%	93.7%
West Facing (270)	85.7%	88.8%	85.0%	86.5%

Temporal Benefits for Avoided Transmission Charges Review

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- The majority of charges for transmission services are based on the peak hour each month for a service area, and Rhode Island is one service area
- The load in any service area is reconstituted for generation within a service area that is not behind a customer load meter and actually reducing the customer load
- For generation like all that is enrolled in RE Growth, the generation is added back to the substation metered loads at the peak hour to determine total transmission service charges
- These rules are part of the ISO-NE tariffs
- As a result, no temporal value from such solar arrays for the reduction of transmission service charges can be realized

Future Plan for Locational Incentives Research

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- Provide update to DG Board on our work and findings – Sept. 25
- Feb-May 2018 – Restart investigation of research with updated line data and new forecasts, new forecast elements (if any), application of the BCA Framework, and more robust constraint analysis that is line specific
- May-June 2018 – Stakeholder engagement on program design
- July 2018 -- Present and discuss final findings with OER and Division, and make recommendation on inclusion in Program filing
- Aug 2018 – Tariff revisions for any proposed incentive structure

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Appendix 6 – New York Locational Value of Distributed Energy Resources

New York Locational Value of Distributed Energy Resources

Background

As part of its Reforming the Energy Vision (REV) initiative, in 2015 the New York State Public Service Commission (PSC) established a proceeding to replace net energy metering (NEM) with mechanisms to compensate Distributed Energy Resources (DER) that more accurately reflect the value they provide to the electric system. The VDER Phase One Order[38], issued March 9, 2017, adopted the Value Stack tariff as a mechanism to compensate newly interconnecting large DER projects, including Community Distributed Generation (CDG) and remote net metered projects, as well as on-site projects located behind the meter of large C&I customers, for net energy injections onto the system. National Grid's Phase One Value Stack tariff became effective November 1, 2017. VDER Phase Two, which began in the summer of 2017, is on-going and, among other objectives, seeks to refine the Value Stack compensation components to more precisely reflect system values.

The Phase One Value Stack tariff includes two components to compensate qualifying DER for distribution system benefits provided: the Location System Relief Value (LSRV) and the Demand Reduction Value (DRV). Both the LSRV and DRV include a performance component where resources are paid for their contribution during the system's top 10 load hours. LSRV is a locational marginal cost for constraints on the system that could be relieved with DER. The DRV component represents the value that exists for T&D by virtue of DER being on the system. In the absence of locational marginal avoided distribution costs, the Commission directed each utility in the VDER Phase One Order to administratively "deaverage" the system average marginal costs calculated in its most recently filed Marginal Cost of Service study to arrive at initial LSRV and DRV values. Further, the Commission required each utility to file a work plan and timeline by April 24, 2017.[39] The Company's work plan filed in compliance with this requirement provided an outline for an Enhanced Marginal Cost of Service study to identify areas on its system where injecting DER may avoid distribution costs, the MW demand reduction needed to avoid them, and to develop associated locational marginal avoided distribution costs, and file the results at the time of filing the Company's 2018 Distributed System Implementation Plan (DSIP). The Company filed its enhanced Marginal Cost of Service study, hereafter known as the Marginal Avoided Distribution Capacity (MADC) study, on July 31, 2018. Further explanation of the MADC is included later in the Marginal Avoided Distribution Capacity (MADC) Study section.

Current Status of VDER Proceeding

On July 26, 2018, New York Staff filed the *Staff Whitepaper on Future Community Distributed Generation Compensation* (hereafter referred to as the Whitepaper) in response to Case 15-E-

[38] Case 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources et al*., Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Phase One Order").

[39] *Ibid*., p. 155 (*see* ordering clause No. 13).

0751, In the Matter of the Value of Distributed Energy Resources, and Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

Based on the New York Public Service Commission's guidance, the current status of the market, and analysis performed by Staff and the New York State Energy Research and Development Authority (NYSERDA), the Whitepaper outlines the following changes for National Grid:

(1) Remaining capacity within each territory should be reallocated and divided between two new Tranches, Tranche 5 and 6, with enhanced Market Transition Credit (MTC)[40] values (this applies for National Grid, as well as for Rochester Gas and Electric Corporation (RG&E) and New York State Electric & Gas Corporation (NYSEG));

(2) In addition, to further ensure that all New Yorkers are able to take advantage of the benefits of Community Distributed Generation (CDG), Staff will work with NYSERDA and stakeholders to investigate and propose options for allowing submetered customers to receive the MTC or similar compensation.

In considering the various options available for CDG compensation beyond Tranche 4, Staff is guided by the New York Public Service Commission's direction to evaluate the viability of a statewide MTC and to develop recommendations for moving beyond Tranche 4 that would not unreasonably burden a particular group of ratepayers. Consideration of a statewide-funded MTC or similar mechanism also offers the opportunity to evaluate the status and viability of currently open Tranches in each utility service territory and ensure that reasonable and viable opportunities for distributed generation are available across the state, along with fairly allocating the costs associated with the MTC.

As these Tranches become filled and the incentives exhausted, Staff will continue to work with NYSERDA and stakeholders under the VDER transition to evaluate further market changes, including the implementation of cost reduction initiatives and improved Value Stack components, and determine what further intervention is appropriate.

New York Analysis as a Model for Rhode Island Analysis

The Company's New York jurisdiction is involved in an ongoing, multi-year process of developing a mechanism to transition to a new way to compensate DER. It is important to understand how net metering policy, the adoption rates of DG, and the forecasting methods in New York differ from Rhode Island, and for these three reasons, the Company does not propose

[40] The VDER Phase One Order established Phase One Net Energy Metering (NEM), which includes a limited continuation of NEM-style compensation, and an adder to the Value Stack for mass market customers, which is referred to as the Market Transition Credit (MTC).

to follow the NY VDER process. Table LI-1 explains these three reasons, the application in New York VDER proceeding, and the reasons why it does not apply to Rhode Island.

Table LI-1: Rhode Island Simplified Interconnection Application Trends

	New York VDER	Rhode Island
Net Metering	Location System Relief Value (LSRV) is not an incentive in addition to net metering. It is a price signal designed to replace net metering.	Net metering is still applicable in Rhode Island. For this reason, the application of New York's Location System Relief Value cannot be applied in Rhode Island.
DG Installation	The expressed purpose of LSRV is to compensate DER and spur development of community distributed generation in areas where it has not flourished.	Rhode Island has a long and successful history of incentivizing developers to install DG. The need that exists to create this locational price signal to support DG in New York does not exist in Rhode Island.
Bottom Up Forecast	The Bottom Up (BU) Forecast is used in the NY DSIP. Over the next 4 to 5 years, the NY team is creating a BU forecast with more data on DG, EV loads, electrical efficiency, and energy storage solutions.	Rhode Island is observing the efforts in NY to learn from their analysis. A BU Forecast is not built into the current RI work plan.

Marginal Avoided Distribution Capacity (MADC) Study

The Company filed its enhanced Marginal Cost of Service study, hereafter known as the Marginal Avoided Distribution Capacity (MADC) study, on July 31, 2018. The MADC values resulting from the study reflect the marginal cost of forecast utility investments that may be avoided by DER that inject energy into the system or reduce load. The MADC operates at the granularity of the specific project (i.e. upgrading a transformer bank) which could be deferred by DER. MADC study outputs include locations where DER can defer the traditional project, which are generally at the feeder level but, in select cases, include higher-voltage lines. MADC outputs can be used as the basis for the LSRV and DRV components of the VDER Value Stack tariff and other purposes, such as compensation rates for demand response and targeted energy efficiency programs. Development of the MADC study required a team of ten engineers, with input from multiple functional units within the Company, to implement new processes and expanded capabilities across a range of software packages including PSSE®, ASPEN, TARA, Python, and Excel. New York Department of Public Service (DPS) Staff has stated the MADC study will be subject to approval by the Commission but, at this time, a regulatory process or timeline for such approval has not been established.

The MADC study was developed to determine locational values through a forward-looking system-wide assessment to determine (1) where DER may be able to provide locational support to the electric distribution system through targeted relief in areas where load growth will create electrical stress on the system, and (2) assigns a value to that relief by comparing it to the traditional investment needed to alleviate such problems. The MADC values provide estimates of the value of marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the 10-year study horizon for each location. For the purpose of implementing the LSRV component of the Value Stack, the Company has bundled locational values into six pricing groups combining projects with a similar dollar per MW value to ease implementation and send a more consistent signal to the market.

As articulated in Section III of the Company's Work Plan and Timeline, the MADC study consists of four basic steps as follows:

A. Development of System-Wide Load Flow Model
B. Development of Load and DER Forecasts at the Substation Level
C. Identification of Potential DER Opportunities to Address System Needs
D. Evaluation of Locational Values

A. System-Wide Load Flow Model

In order to develop an accurate assessment of locational distribution system marginal costs, National Grid developed an improved load flow model built upon the models submitted, along with the other New York Transmission Owners, through the New York Independent System Operator (NYISO) in the aggregated 2017 FERC 715 Filing which capture 2018 and 2027 summer peak 90/10 extreme loading cases consistent with a one-in-ten-year weather event. However, as those transmission-level load flow models are not sufficiently detailed for the purpose of the MADC study, the Company expanded the topology of the transmission load flow cases to include additional detail at lower transmission levels, the sub-transmission system, and the distribution system, including all distribution substation transformers and the corresponding low-side bus at each of these substations. This increased granularity resulted in a more integrated assessment of system impacts than previous planning approaches.

B. Load and DER Forecasting at the Substation Level

As proposed in the Work Plan and Timeline, the Company developed multiple sets of load and DER forecasts for each distribution substation. The MADC study evaluates two sets of forward-looking ten-year forecasts: a top-down forecast based on data available from the NYISO zonal level load data and growth trends, and a bottom-up Company forecast utilizing customer-level information to develop feeder-specific, 8,760 hour load profiles over the study horizon. The top-down zonal forecasts are disaggregated down to individual substations and the bottom-up feeder-level forecasts are aggregated or "rolled up" to create similar substation views. The bottom-up forecasts include the load of existing customers and scaling factors to account for projected loads from new customers.

While developed through different processes, National Grid applied both forecasts consistently as inputs to the load flow model. Both forecasts were built from a 2017 base year and then calibrated for a 95/5 weather event, consistent with the Company's traditional distribution planning practices. The Company processed load flow assessments for both forecasts considering two DER scenarios: (1) without additional rooftop photovoltaic systems beyond those presently installed and (2) incorporating forecasted rooftop solar PV additions.

The following forecasts were evaluated in load flow cases:

1. 2018 summer 95/5 peak
2. 2027 summer 95/5 peak bottom-up load forecasts including new rooftop solar PV
3. 2027 summer 95/5 peak bottom-up load forecasts excluding new rooftop solar PV
4. 2027 summer 95/5 peak top-down load forecasts including new rooftop solar PV
5. 2027 summer 95/5 peak top-down load forecasts excluding new rooftop solar PV

C. Identification of DER Opportunities

Multiple load flow cases were analyzed to assess the system performance during coincident peak loading as well as during more localized non-coincident peak loading to capture the strain on local infrastructure. System needs considered thermal constraints, voltage excursions, and contingency at-risk load. For the duration of the ten-year study horizon, the model identified the specific constrained assets, the timing at which the planning criteria violations are forecasted to materialize and the kW magnitude of relief required to address the violation.

The Company's engineering teams then developed traditional utility solutions for each of the violations identified from the load flow analyses. The cost estimates for each of the traditional solutions were based on recent projects and cost projections embedded in the Company's 2018 Three-Year Rate Case Order. The Company evaluated results from the load flow analyses against planning criteria to identify potential projects where the addition of DER could provide alternatives to traditional investment. Generally, if a need could be addressed by the capacity of DER, it was identified for further consideration with two exceptions. Projects were removed from the MADC study if an asset was already scheduled to be replaced due to age or state of repair (i.e., "asset condition,") and only if the updated infrastructure solved the constraint identified by the load flow model. Similarly, an existing project was removed from the MADC study if it appeared in National Grid's Capital Improvement Plan (CIP) with an in-service date of 2020 or earlier. These imminent-need projects were excluded because the Company needs to replace those assets to meet planning standards for safe and reliable service regardless of the quantity of DER on the system.

For each defined violation, the Company created a list of locations where DER performance, aligned with system need, would be beneficial. In most cases, the locations include a list of feeders. In select cases, they also include higher voltage lines.

In cases where the locations for DER had the possibility to solve more than one model violation, and obviate the need for multiple potential projects, the Company adjusted the projected value of those locations appropriately given the type of project and size of the need.

D. Enhanced MCOS Study

As in the traditional MCOS study, the crux of the MADC study is representing utility spending in a $/kW fashion. The Company used the study results – the size of the need, the timing, and the cost of the traditional solution – to generate a schedule of revenue requirements that could be deferred by DER. This is conceptually similar to the procedure the Company used in assessing its Village of Kenmore non-wires alternative (NWA) project and plans to use going forward to evaluate other NWA opportunities.

The MADC study results are unique estimates of the value of a marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the ten-year study horizon for each location. This $/kW estimate can become the basis for locational compensation in expanded DR programs or the LSRV in the VDER Value Stack tariff.

The results of the study were used to generate locational MADC values, a schedule of revenue requirements of the 68 unique areas of the Company's system where an appropriate quantity of DER could effectively defer the need for traditional utility investment over the 10-year duration of the study. In New York, National Grid's traditional Marginal Cost of Service (MCOS) study is primarily used for specific ratemaking purposes and (1) does not calculate marginal costs on a locational basis, and (2) is based on a historical sample of utility infrastructure projects that cannot be avoided by demand reductions from DER. In comparison, the expressed purpose of the MADC is to inform compensation for locational distribution system costs that may be avoided by DER.

The MADC study was developed to determine locational values through a forward-looking system-wide assessment to determine (1) where DER may be able to provide locational support to the electric distribution system through targeted relief in areas where load growth will create electrical stress on the system, and (2) assigns a value to that relief by comparing it to the traditional investment needed to alleviate such problems. The MADC values provide estimates of the value of marginal increment of load relief on a $/kW basis based on the potential to defer the proposed traditional investment over the 10-year study horizon for each location. This $/kW estimate can become the basis for locational compensation in expanded demand response programs, targeted Energy Efficiency programs, or the LSRV and DRV components of the VDER Value Stack tariff. For the purpose of implementing the LSRV component of the Value Stack, the Company has bundled locational values into six pricing groups combining projects with a similar dollar per MW value to ease implementation and send a more consistent signal to the market.

The MADC study is structured in the following manner: ignores sunk costs and only analyzes future projects over the scope of the 10-year study period; focuses only on capital costs which may be avoided or deferred by changes in load and demand; considers locational specific values at the substation or distribution feeder level, down to the granularity of the traditional project which could be deferred or avoided.

Creating the New York MADC study required four steps:

1. Development of System-Wide Load Flow Model
2. Development of Load and DER Forecast at the Substation Level
3. Identification of Potential DER Opportunities to Address System Needs
4. Evaluation of Locational Values for MADC Study

Development of a system-wide load flow model was necessary in order to develop an accurate assessment of marginal costs on locations on the distribution system. The existing transmission load flow models were not sufficiently detailed, so the Company expanded the topology of the transmission load flow cases to include additional detail at lower transmission levels, the sub-transmissions system, and the distribution system including all distribution substation transformers and the low-side bus at each of these substations.

The MADC was then applied to determine the LSRV value and the DRV value for the VDER Value Stack tariff.

Appendix 7 – 2011 Least Cost Procurement Standards with Proposed 2014 Revisions Approved in Docket No. 4443

2011 Least Cost Procurement Standards with Proposed 2014 Revisions

CHAPTER 1 – Energy Efficiency Procurement

1. **Section 1.1 Plan Filing Dates**

   A. The Utility Energy Efficiency Procurement Plan ("The EE Procurement 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.

   B. The Utility shall prepare and file a supplemental filing containing details of implementation plans by program for the next program year ("The EE Program Plan"). Beginning in 2014, the EE Program Plan shall be filed on October 15 except in years in which an EE Procurement Plan is filed; in those years, the EE Program Plan filing shall be made on November 1. The EE Program Plan filings shall also provide for adjustment, as necessary, to the remaining years of the EE Procurement Plan based on experience, ramp-up, and increased assessment of the resource levels available.

2. **Section 1.2 EE Procurement Plan Components**

   A. The EE Procurement 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 and are prudent and reliable.

   i. Strategies and approaches to planning:

   a. The Utility shall use the Council's Opportunity Report as issued on July 15, 2008 (and as it may be subsequently supplemented or updated to identify the cost effective energy efficiency potential and opportunities) as one resource among others in developing its EE Procurement Plan. The Utility may include in its Plans an outline of proposed strategies to supplement and build upon the initial Opportunity Report.

   b. The EE Procurement Plan shall describe the recent energy efficiency programs offered by the Utility and highlight how the EE Procurement Plan supplements and expands upon these offerings, including but not limited to new measures, implementation strategies, measures specifically intended for demand management, new strategies to make capital available to effectively overcome market barriers, and new programs as appropriate.

   c. The EE Procurement Plan shall include a section describing a proposal to investigate new strategies to make available the capital needed to implement projects in addition to the incentives provided. Such proposed strategies shall move beyond traditional financing strategies and shall include new capital availability strategies that effectively overcome market barriers in each market segment in which it is feasible to do so.

d. The EE Procurement Plan shall address how the utility plans to integrate gas and electric energy efficiency programs to optimize customer energy efficiency.

e. The EE Procurement Plan should address new and emerging issues as they relate to least cost procurement (CHP, strategic electrification, integration of grid modernization, gas service expansion, etc.), as appropriate, including how they may provide system, customer, environmental, and societal benefits.

ii. Cost-effectiveness

a. The Utility shall assess measure, program and portfolio cost-effectiveness according to the Total Resource Cost test ("TRC")[1] The Utility shall, after consultation with the Council, propose the specific benefits and costs to be reported and factors to be included in the Rhode Island TRC test and include them in the EE Procurement Plan. These benefits may include resource impacts and non-energy impacts. The accrual of non-energy impacts to only specific programs or technologies, such as income-eligible programs or combined heat and power, may be considered.

b. That test shall include the costs of CO2 mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative. The 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.

c. Benefits and costs that are projected to occur over the term of each EE Program Plan shall be stated in present value terms in the TRC test calculation, using a discount rate that appropriately reflects the risks of the investment of customer funds in energy efficiency; in other words, a low-risk discount rate which would indicate 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 for each EE Program Plan, as appropriate, to ensure that the applied discount rate is based on the most recent information available.

d. The utility shall provide a discussion of the carbon impacts efficiency and reliability investment plans will create.

iii. Prudency and Reliability

a. In the initial three-year EE Procurement Plan, a ramp-up to achieve all cost-effective efficiency lower cost than supply shall be proposed by the Utility that is both aggressive in securing energy, capacity, and system

[1] Since the focus of the Rhode Island legislation is on securing customer benefits, not just Utility benefits from energy efficiency procurement, the TRC test is recommended.

cost savings and is also designed to ensure the programs will be delivered successfully and cost-effectively over the long term[2]. The proposed ramp-up will appropriately balance the significant cost saving efficiency investment opportunity that is identified and the near-term capacity and staffing issues within the utility and vendor community with an emphasis on ensuring an aggressive and sustainable ramp-up of program investments over time.

b. Subsequent Least Cost Procurement Plans shall be developed to propose strategies to achieve the energy efficiency savings targets that shall be approved by the Commission for that three year period. Such strategies shall continue to secure energy, capacity, and system benefits and also be designed to ensure the programs will be delivered successfully and cost-effectively over the long term. In addition to satisfying other provisions of these Standards, the EE Procurement Plan shall continue to 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.

c. EE Procurement Plan 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 today's efficiency programs.

d. The EE Procurement Plan should describe how it interacts with the System Reliability Procurement Plan.

iv. Funding Plan and Initial Goals

a. The Utility shall develop a funding plan using, as necessary, the following sources of funding to meet the budget requirement of the EE Procurement Plan and fulfill the statutory mandate of Least Cost Procurement. The Utility shall utilize as necessary, 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 § 23-82.6 of the General Laws;

[2] The Utility may propose a study or studies to investigate and document current energy efficiency program infrastructure in Rhode Island; to assess the ability of the infrastructure to meet increased demand for energy efficiency services; and to make recommendations for increasing capacity if needed. Any such report should address: staffing levels and ability to expand staffing; training and experience of staff; current workloads; interest in working with utility program sponsors; statewide coverage of services; and other relevant factors. Where appropriate, the Utility may partner with research efforts of this sort that are regional in nature or in other jurisdictions, so long as they provide pertinent information for building the Rhode Island infrastructure. The costs of these plans and the actions to implement them may be included as program costs.

(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.G.L. § 39-1-27.7, which is a funding mechanism to be relied upon after the other sources as needed to fully fund cost-effective 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.

(6) other sources as may be identified by the EERMC and the Utility.

b. The Utility shall include a preliminary budget for the EE Procurement Plan covering the three-year period that identifies the projected costs, benefits, and initial energy saving goals of the portfolio for each year. The budget shall identify at the portfolio level, the projected cost of efficiency resources in cents/ lifetime kWh. The preliminary budget and initial energy saving goals may be updated in the Utility's EE Program Plan.

B. Efficiency Performance Incentive Plan

i. Pursuant to R.I.G.L. § 39-1-27.7(e) and § 39-1-27.7.1, the Utility shall have an opportunity to earn a shareholder incentive that is dependent on its performance in implementing the approved EE Procurement Plan

a. The Utility, in consultation with the Council, will propose in its EE Procurement Plan a Performance Incentive (PI) proposal that is designed to promote superior Utility performance in cost-effectively and efficiently securing for customers all efficiency resources lower cost than supply.

b. The Performance Incentive 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.

c. The Utility PI model currently in place in RI should be reviewed by the Utility and the Council. The Utility 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.

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

e. The PI should be sufficient to provide a high level of motivation for excellent Utility performance annually and over the three year period of the EE Procurement Plan, but modest enough to ensure that customers receive most of the benefit from energy efficiency implementation.

3. **<u>Section 1.3 EE Program Plan Components</u>**

A. Principles of Program Design

i. The EE Program Plan shall identify the specific energy efficiency programs proposed for implementation by the Utility, pursuant to the EE Procurement Plan.

ii. The Utility should consistently design programs and strategies to ensure that all customers have an opportunity to benefit comprehensively, where appropriate, from expanded investments in this low-cost resource and the programs should be designed and implemented in a coordinated fashion by the utility, in active and ongoing consultation with the Council.

iii. The Utility shall propose a portfolio of programs in the EE Program 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.

a. The Utility 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.

b. The Utility shall allocate funds to the Energy Efficiency and Resource Management Council and Office of Energy Resources as specified in R.I.G.L. § 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.

iv. All efforts to establish and maintain program capability as identified in Section 1.2 A iii 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.

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

vi. 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 Utility should design programs to capture all resources that are cost-effective and lower cost than supply. The Utility should consult with the Council to address ongoing issues of Parity.

vii. The Utility shall explore as part of its plan, new strategies to make available the capital needed to effectively overcome market barriers and implement projects that moves beyond traditional financing strategies.

B. <u>Final Funding Plan and Budget Amounts, Cost-Effectiveness and Goals</u>

i. The Utility shall include a detailed budget for the EE Program 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.

ii. The EE Program plans filed November 1 will reflect program implementation experience and anticipated changes, shifts in customer demand, changing market costs, and other factors, as noted in Section 1 above. 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.

iii. The EE Program Plan shall identify the energy cost savings and typical bill impacts that RI ratepayers will realize through its implementation.

iv. In order to assess the potential effect of greenhouse gas reduction costs, the Utility, upon consultation with the Council, may conduct and report in the EE Program Plan filing a sensitivity analysis of the cost-effectiveness of the proposed portfolio of programs that includes a "potential" avoided cost for CO2 mitigation that is agreed upon among the parties.

C. Program Descriptions

i. Utility program development shall proceed by building upon what has been learned to date in utility program experience, systematically identifying new opportunities and pursuing comprehensiveness of measure implementation as appropriate and feasible.

ii. The Utility shall, as part of its EE Program Plan, describe each program, how it will be implemented, and the total costs and benefits associated with the efficiency investments

iii. The Utility plan shall describe in each appropriate program section a plan to devise new strategies to make available the capital needed in addition to the incentives provided to implement measures.

iv. In addition to these basic requirements, the 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 and standards and other market transforming strategies. If the utility 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 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.

D. Monitoring & Evaluation (M&E) Plan

i. The Utility shall, after consultation with the Council, include a Monitoring and Evaluation ("M & E") component in its EE Program Plan.

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

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

b. a component that will address 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 Utility is participating in or plans to participate in; and

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

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

E. Reporting Requirements

i. The Utility, 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.

4. Section 1.4 Role of the Council

A. The Council shall take a leadership role in ensuring that Rhode Island ratepayers receive excellent value from the EE Procurement Plan being implemented on their behalf. The Council shall do this by collaborating closely with the Utility on design and implementation of the Monitoring and Evaluation efforts presented by the Utility under the terms of Section 1.3 D, and if necessary, provide recommendations for modification that will strengthen the assessment of utility programs.

B. As part of the Council's April 15 annual report required by R.I.G.L. §42-140.1-5 the Council shall report on program performance and whether program costs are justified, given the intent of the enabling legislation. The Council shall also report on the effectiveness of any performance incentive approved by the PUC in achieving the objectives of efficient and cost-effective procurement of all efficiency resources lower cost than supply and the level of its success in mitigating the cost and variability of electric service by reducing customer usage.

C. In addition to the other roles for the Council indicated in this filing, the Utility shall seek ongoing input from, and collaboration with the Council on development of the EE Procurement and Program Plans, and on development of annual updates, if any, to the EE Procurement Plan.

D. The Utility 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.

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

F. The Utility shall, in consultation with the Council, propose a process for Council input and review of its EE Procurement Plan and EE Program Plan. This process is intended to build on the mutual expertise and interests of the Council and the Utility, as well as meet the oversight responsibilities of the Council.

G. The Utility shall submit a draft annual EE Program 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.

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

I. The Council shall prepare memos on its assessment of the cost effectiveness of the Least Cost Procurement Plan and annual EE Program Plans, pursuant to R.I.G.L. §39-1-27.7(c)(5), and submit them to the PUC no later than two weeks following the filing of the respective Plans with the Commission.

CHAPTER 2 - System Reliability Procurement
Section 2.1 Distributed/Targeted Resources in Relation to T &D Investments

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into National Grid's ("the Company") distribution planning process for the three years of implementation beginning January 1 of the following year. The System Reliability Procurement Plan should be integrated with the Energy Efficiency Procurement Plan and designed to manage demand and optimize grid performance, using customer side resources.

B. Non-Wires Alternatives (NWA) may include but are not limited to:
   a. Least Cost Procurement energy efficiency baseline services;

b. Peak demand and geographically-focused supplemental energy efficiency strategies;
c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[3];
d. Demand response;
e. Direct load control;
f. Energy storage, including electric vehicles;
g. Alternative metering and tariff options, including time-varying rates.

C. Investments in grid-facing technologies that further optimize grid performance may be considered and coordinated with the System Reliability Procurement Plan.[4]

D. Identified transmission or distribution (T &D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWAs that could reduce, avoid or defer the T&D wires solution over an identified time period.
a. The need is not based on asset condition;
b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
c. If load reductions are necessary, then they are expected to be less than 20percent of the relevant peak load in the area of the defined need;
d. Start of wires alternative construction is at least 36 months in the future;
e. At its discretion the utility 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.

A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

E. Feasible NWAs will be compared to traditional solutions based on the following:
a. Ability to meet the identified system needs;
b. Anticipated reliability of the alternatives;
c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies);
d. Potential for synergy savings based on alternatives that address multiple needs
e. Operational complexity and flexibility;
f. Implementation issues;
g. Customer impacts to potentially modify usage at certain times and seasons;
h. Other relevant factors.

F. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA. The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in(D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the Total Resource Cost test

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[3] 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.

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

(TRC)[5].Consideration of the net present value of resulting revenue requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

G. For each need where a NW A is the preferred solution, the distribution utility will develop an Implementation plan that includes the following:
   a. Characterization of the need
      i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues.
      ii. Identification and description of the T&D investment and how it would change as a result of the NWA.
      iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade.
      iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions.
      v. Ability of affected customers to participate in the proposed project
   b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
   c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing.
   d. Development of NWA investment scenario(s)
      i. Specific NWA characteristics
      ii. Development of an implementation plan, including ownership and contracting considerations or options
      iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule.

H. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

i. Capital funds that would otherwise be applied towards traditional wires based alternatives, where the costs for the NW A 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
ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans.
iii. Additional energy efficiency funds to the extent that the energy efficiency-related NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved
iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed;

[5]The TRC test may be appropriately modified to account for the value of reliability and other site-specific and NWA-appropriate costs, benefits, and risks.

v. Identification of significant 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.
vi. Any other funding that might be required and available to complete the NWA.

I. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
   a. Identification of projects which passed the initial screening in section (C);
   b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
   c. Implementation plan for the selected NW A projects;
   d. Funding plan for the selected NW A projects;
   e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
   f. Status of any previously selected and approved projects and pilots;
   g. Identification of any methodological or analytical tools to be developed in the year;
   h. Total SRP Plan budget, including administrative and evaluation costs.

J. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

K. To the extent the implementation of a NW A may contribute to an outage event that is beyond the control of the Company, the Company may apply to the Commission for an exclusion of such event in the determination of Service Quality performance.

Chapter 3: Aligning Utility Incentives & Reforming Rates

The Energy Efficiency and Resource Management Council and the Company shall review existing rates and incentive structures and, as needed, propose adjustments to align utility and consumer incentives with the objectives of Least Cost Procurement and System Reliability Procurement.

Appendix 8 – 2018 Market and Engagement Plan

SYSTEM RELIABILITY PROCUREMENT

2018 Marketing and Engagement Plan

Table of Contents

Introduction

As stated in the 2018 System Reliability Procurement Report:

This section proposes marketing and customer engagement initiatives for 2018 intended to provide more information to stakeholders, customers, and third parties regarding the status of the Company's RI plan to raise awareness of, and increase engagement with, the Data Portal and System Heat Map. The Company plans to complete an initial version of the Portal by June 30, 2018.

As agreed to in the initial filing, there may be additional opportunities for installations of technologies that reduce peak load outside of the Company's consideration and proposal of cost-effective NWA projects. To nurture these inherent opportunities with the work the Company is doing on the Rhode Island System Data Portal (Portal), and to encourage DER solution providers to support the strategic deployment of these solutions to benefit constrained areas, the Company proposes to develop and deploy a marketing and engagement plan in 2018.

This marketing and engagement plan would promote the Portal and heat map resources described in the 2018 System Reliability Procurement Report as they become available to all appropriate parties interested in and capable of creating, submitting and potentially developing innovative energy solutions across Rhode Island.

The Company's customer communication channels have universal reach throughout its service territory, and the Company communicates with customers on at least a monthly basis through bills, home energy reports, and less regularly through other channels such as email, social media, billboards, print, and radio media. The Company is a national leader in communicating to customers including large and small business as well as interested market participants about energy efficient products, services and potential opportunities to work together. Therefore, the Company will leverage these capabilities and develop a Marketing and Engagement Plan that will educate these parties on the benefits of the Portal and the Heat Map.

The campaign will go live by May 31, 2018 to support the deployment of resources identified in item (1) of the Rhode Island System Data Portal & Heat Map Resources section in the 2018 System Reliability Procurement Report by June 30, 2018.

For the Market Engagement Funding Plan, please refer directly to the 2018 System Reliability Procurement Report.

Projected Campaign Start

May 31 Marketing Start, June 30 Portal Go Live

Campaign Objective

To raise awareness and drive engagement with the RI System Data Portal and the Heat Map to all appropriate Rhode Island parties, especially developers, interested in and capable of creating, submitting and potentially developing innovative energy solutions to illustrate 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.

Marketing Plan & Development

The Company will work in a cost-efficient manner to develop an engaging Business to Business marketing campaign that includes messaging, graphics/visuals, tactics and planning leveraged & optimized across the following primary potential marketing channels:

- **Educational Webinar** – Webinar overview to introduce the Portal and Heat Map for interested parties including examples of how to access and use the information contained within.
- **Paid Search** – Use Search Engine Marketing (SEM) to market the RI System Data Portal & heat map with search engine keywords and Search Engine Optimization (SEO) by paying to prioritize/optimize the portal and map in identified searches via engines like google, yahoo, etc.
- **Social media** – Use of LinkedIn, Facebook and Instagram ads targeted and re-messaged in a thoughtful way to appropriate groups, businesses & customers to keep the portal and/or the heat map top of mind for the duration of the campaign.
- **Direct mail** – An email outlining the availability of the Portal and the Heat Map will be communicated via email to appropriate parties.
- **Digital Banners –** Digital ads on TBD appropriate sites & pages of related services & providers.
- **Feedback/Contact Channels** – Creating dedicated email for all appropriate inquiries related to the RI System Data Portal, its use and the opportunities it presents to appropriate parties.
- **Events** – Local Rhode Island events like the Rhode Island Home Show, Grow Smart RI, Trade & Developer Gatherings.

The Company may also consider additional secondary potential marketing channels:

- **Geo-Targeted Mobile Messaging –** Leveraging geo-fencing mobile technology to send SRP/Heat Map messages to hyper targeted event locations to increase awareness.
- **Owned Assets** – Work signage and where appropriate & possible inclusion of RI Data Portal/Heat Map messaging in existing National Grid Business to Business campaigns.

Earned Media – Strategically developed and placed articles in appropriate industry and trade specific publications highlighting the Portal, its purpose and use in an effort to drive appropriate engagement with the portal.

Campaign Tracking/Performance

The Company proposes a host of tactics to measure the effectiveness of messaging and channels on an iterative basis to ensure as effective and efficient use of approved funding as possible. Before establishing goals for each metric there must be alignment on what would constitute an appropriate measurement. Alignment of measurement will be decided upon finalization of the approved marketing plan.

Some metrics may include the following:

- **Event/Webinar Attendance –** How many customers, business representatives, developers etc. attend and engage with National Grid at events promoting the RI Data Portal and Heat Map
- **Web Traffic analytics for RI Data Portal**
    - *Unique Site Visit* – refers to the number of distinct individuals requesting pages from the website during a given period, regardless of how often they visit.
    - *Returning visits (RVR)* – every time a unique first time visitor returns to your site and they rate at which they return
    - *Click through rate (CTR)* – how many visitors (unique or recurring) click on information, pages or hyperlinks found on the page. Also apply this metric to Digital Advertising.
    - *Average Time on Page* – how long a visitor spends on your page
- **Open Rates -** How many distributed emails and digital banner ads are opened.
- **Developer Inquiries/Project Submittals –** How many projects (NWA, Sustainable Project Developments) happen after RI Data Portal & Heat Map go live or are probably developed directly from/with connections made through any of the above-mentioned tactics.
- **Customer Survey -** Creating a thoughtful, easy and interactive brief survey to test the portal's performance with the potential for portal improvements to enhance engagement where possible, appropriate and it is affordable to do so.

In general, National Grid will leverage any or all appropriate, affordable tracking mechanisms to capture effectiveness of the Marketing and Engagement Plan.

Appendix 9 – 2018 Market and Engagement Plan Year-to-Date Results

PLACEHOLDER:

2018 Market and Engagement Plan Year-to-Date Results to be submitted following compilation in October 2018 of the first quarterly report of results for July to September.

Appendix 10 – Tiverton NWA Pilot Benefit-Cost Analysis with the RI Test Applied

Table RIT-S-2
System Reliability Procurement - Tiverton/Little Compton
Summary of Cost-Effectiveness with RI Test Applied ($000)

	2012	2013	2014	2015	2016	2017	2018	Overall
Benefits	**$69.4**	**$686.3**	**$641.0**	**$921.5**	**$611.3**	**$612.8**	**$0.0**	**$3,542.2**
Focused Energy Efficiency Benefits[1]	$32.4	$517.5	$370.0	$688.6	$391.3	$78.09	$0.0	$2,077.8
SRP Energy Efficiency Benefits[2]	$37.0	$168.9	$91.3	$54.6	$55.3	$375.2	$0.0	$782.2
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.3	$0.0	$28.9
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$0.0	$653.3
Costs	**$101.5**	**$519.6**	**$529.7**	**$997.5**	**$594.2**	**$510.9**	**$90.8**	**$3,344.2**
Focused Energy Efficiency Costs[5]	$14.7	$178.3	$156.2	$497.4	$263.1	$281.3	$0.0	$1,390.9
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$229.6	$90.8	$1,953.3
Benefit/Cost Ratio	**0.68**	**1.32**	**1.21**	**0.92**	**1.03**	**1.20**	**-**	**1.06**

Notes:

(1) Focused EE benefits in each year include the NPV (over the life of those measures) of all **RI Test** benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.

(2) SRP EE benefits include all **RI Test** benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.

(3) DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.

(4) Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.

(5) EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install programs. These are the programs through which measures in this SRP pilot will be offered.

(6) SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.

(7) All costs and benefits are in $current year except for deferral benefits.

(8) 2012-2017 numbers have been updated to reflect year end data. 2018 numbers reflect year end projections.

Table RIT-S-5
System Reliability Procurement - Tiverton/Little Compton
Summary of Incremental Benefits By Year with RI Test Applied

			Capacity ($)						Energy ($)					Non-Electric ($)	
			Total Benefits	Summer Generation	Winter Generation	Transmission	MDC/ Deferral(3)	DRIPE	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	DRIPE	Resource	Non - Resource
2012	EE	Residential	19,530	553	0	648	1,251	4	2,972	1,710	1,618	784	2,439	0	7,552
		Commercial	12,892	1,503	0	1,835	1,595	0	1,163	301	452	108	2,716	0	3,218
		SRP	36,965	1,066	0	1,352	1,176	0	511	707	215	257	1,739	29,941	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**69,386**	**3,122**	**0**	**3,835**	**4,022**	**4**	**4,646**	**2,718**	**2,284**	**1,150**	**6,894**	**29,941**	**10,770**
2013	EE	Residential	258,205	4,023	0	4,755	7,009	161	16,469	10,174	8,357	4,394	20,135	137,159	45,569
		Commercial	259,262	26,861	0	33,980	29,546	1	42,603	11,019	16,306	3,931	95,016	0	0
		SRP	168,872	35,799	0	43,540	41,482	354	2,351	3,363	12,313	5,345	24,325	0	0
	Non-EE	Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
		Deferral	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total	**686,339**	**66,683**	**0**	**82,275**	**78,037**	**515**	**61,424**	**24,556**	**36,976**	**13,669**	**139,477**	**137,159**	**45,569**
2014	EE	Residential	299,185	9,238	0	11,214	0	80	27,777	16,290	10,804	6,076	68,995	118,073	30,639
		Commercial	70,811	5,786	0	7,334	0	0	14,592	3,775	5,577	1,346	32,400	0	0
		SRP	91,259	27,489	0	33,575	0	0	723	1,063	8,814	3,527	16,066	0	0
	Non-EE	Demand Reduction	5,563	1,989	0	3,521	0	0	0	0	54	0	0	0	0
		Deferral	174,188	0	0	0	174,188	0	0	0	0	0	0	0	0
		Total	**641,007**	**44,502**	**0**	**55,645**	**174,188**	**80**	**43,092**	**21,129**	**25,249**	**10,949**	**117,461**	**118,072**	**30,639**
2015	EE	Residential	620,460	27,634	0	34,191	0	8	81,099	42,535	30,530	15,480	215,390	126,749	46,844
		Commercial	68,095	11,410	0	14,466	0	0	11,417	2,970	4,450	1,081	22,301	0	0
		SRP	54,643	16,446	0	20,228	0	0	570	839	5,157	2,145	9,257	0	0
	Non-EE	Demand Reduction	6,802	2,411	0	4,074	0	0	0	0	317	0	0	0	0
		Deferral	171,482	0	0	0	171,482	0	0	0	0	0	0	0	0
		Total	**921,481**	**57,901**	**0**	**72,959**	**171,482**	**9**	**93,086**	**46,345**	**40,454**	**18,705**	**246,948**	**126,749**	**46,844**
2016	EE	Residential	349,439	16,665	0	20,972	0	0	49,371	27,102	17,983	10,105	126,374	59,601	21,267
		Commercial	41,863	3,841	0	4,778	0	0	9,563	2,483	3,711	901	16,586	0	0
		SRP	55,287	11,404	0	13,774	0	0	476	777	2,930	1,418	6,063	18,445	0
	Non-EE	Demand Reduction	5,260	3,604	0	1,224	0	0	0	0	431	0	0	0	0
		Deferral	159,412	0	0	0	159,412	0	0	0	0	0	0	0	0
		Total	**611,261**	**35,515**	**0**	**40,749**	**159,412**	**1**	**59,410**	**30,362**	**25,055**	**12,423**	**149,022**	**78,046**	**21,267**
2017	EE	Residential	427,439	18,122	0	22,848	0	0	46,569	26,122	18,280	10,531	115,601	144,298	25,067
		Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
		SRP	391,142	16,228	0	20,444	0	0	40,135	21,141	16,469	8,192	99,168	144,298	25,067
	Non-EE	Demand Reduction	11,320	9,853	0	1,106	0	0	0	0	362	0	0	0	0
		Deferral	148,191	0	0	0	148,191	0	0	0	0	0	0	0	0
		Total	**978,092**	**44,203**	**0**	**44,397**	**148,191**	**1**	**86,704**	**47,263**	**35,111**	**18,722**	**214,770**	**288,596**	**50,133**
Grand Total			**3,907,566**	**251,926**	**0**	**299,859**	**735,331**	**610**	**348,362**	**172,373**	**165,129**	**75,619**	**874,572**	**778,564**	**205,222**

Notes:
(1) The "EE" benefits include both Focused Energy Efficiency benefits and SRP Energy Efficiency benefits.
(2) Measures unique to SRP are listed as a separate line item under the EE heading. Measures part of the focused EE are listed in the EnergyWise and Small Business program lines.
(3) The MDC/Deferral column represents: 2012-2013: the system-average distribution benefit and 2014-2017: the calculated deferral benefit as defined in the notes section of **Table RIT-S-2**
(4) All benefits are in $current year except deferral benefits which are in $2014.
(5) 2012-2017 numbers have been updated to reflect year end data.
(6) Benefits due to EE reflect new installations within the year. Benefits due to Non-EE reflect cumulative installations