The Narragansett Electric Company
d/b/a Rhode Island Energy

2024-2026 System Reliability Procurement (SRP) Three-Year Plan

November 17, 2023

Submitted to:

Rhode Island Public Utilities Commission in
RIPUC Docket No. 23-47-EE

Prepared by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

November 17, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-47-EE – The Narragansett Electric Company d/b/a Rhode Island Energy's 2024-2026 System Reliability Procurement ("SRP") SRP Three-Year Plan

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find Rhode Island Energy's 2024-2026 System Reliability Procurement ("SRP") Plan containing the joint pre-filed testimony of Dr. Lee Gresham and Dr. Carrie A. Gill. This filing is being made in accordance with Chapter 4 of the Least Cost Procurement Standards.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Christy Hetherington, Esq.
John Bell, Division

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

November 17, 2023
Date

Docket No. 23-47-EE – Rhode Island Energy 2024-2026 System Reliability Procurement ("SRP") Three-Year Plan
Service list 11/17/2023

Name/Address	E-mail Distribution List	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew S. Marcaccio, Esq. Celia B. O'Brien, Esq. 280 Melrose St. Providence, RI 02907	AMarcaccio@pplweb.com; JHutchinson@pplweb.com; COBrien@pplweb.com; JScanlon@pplweb.com; SBriggs@pplweb.com; BSFeldman@RIEnergy.com; CAGill@RIEnergy.com; RLGresham@RIEnergy.com; DMMoreira@RIEnergy.com;	401-784-4263
Division of Public Utilities and Carriers Margaret L. Hogan, Esq.	Margaret.L.Hogan@dpuc.ri.gov; Christy.hetherington@dpuc.ri.gov; john.bell@dpuc.ri.gov; Joel.munoz@dpuc.ri.gov; Ellen.golde@dpuc.ri.gov; Paul.Roberti@dpuc.ri.gov;	401-784-2120
Tim Woolf Jennifer Kallay **Synapse Energy Economics** 22 Pearl Street Cambridge, MA 02139	twoolf@synapse-energy.com; jkallay@synapse-energy.com;	
Office of Energy Resources (OER) Albert Vitali, Esq. Dept. of Administration	Albert.Vitali@doa.ri.gov; Nancy.Russolino@doa.ri.gov;	401-222-8880

Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Christopher.Kearns@energy.ri.gov; Steven.Chybowski@energy.ri.gov; William.Owen@energy.ri.gov; Nathan.Cleveland@energy.ri.gov; Karen.Bradbury@energy.ri.gov;	
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk John Harrington, Commission Counsel Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.Harrington@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov ;	401-780-2107
Marisa Desautel, Esq. Desautel Browning Law	marisa@desautelbrowning.com;	401-477-0023
Larry Chretien	Larry@massenergy.org;	
Acadia Center Emily Koo, Director	EKoo@acadiacenter.org;	

JOINT PRE-FILED DIRECT TESTIMONY

OF

CARRIE GILL

AND

LEE GRESHAM

November 17, 2023

Table of Contents

I. <u>Introduction</u>

<u>Carrie Gill</u>

Q. Dr. Gill, please state your name and business address.

A. My name is Carrie Gill. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

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

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") as Senior Manager of Electric Regulatory Strategy within the External Affairs team. In this role, I am responsible for general regulatory matters, policy development, and filings, including providing strategic support to inform business decisions that advance safe, reliable, affordable electricity distribution.

Q. Please describe your educational background and professional experience.

A. I received a doctorate in environmental and natural resource economics from the University of Rhode Island in 2017, masters degrees in business administration and oceanography from the University of Rhode Island in 2010, and a bachelors of science in physics and mathematics from Loyola University, Maryland in 2007.

Prior to my role with Rhode Island Energy, I served multiple positions with the Rhode Island Office of Energy Resources from 2017 to 2022, culminating my tenure as chief economic and policy analyst. In that role, I provided strategic oversight of clean energy and climate policies and programs for the State of Rhode Island. Prior to 2017, I held various research and teaching assistantships within University of Rhode Island (2012-2017); provided independent consulting to a solar thermal developer in Washington, DC (2012); served as a Knauss Fellow within the U.S. Department of Energy's Wind and Water Power Program (2011-2012); and supported the Coastal Resources Center with research on coastal community climate adaption (2010).

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. Yes, I testified on behalf of Rhode Island Energy in Docket No. 23-05-EL (Tariff Advice to Amend the Net Metering Provision), Docket No. 22-56-EL (Grid Modernization Plan), and Docket No. 22-39-REG (2023 Renewable Energy Growth Program).

<u>Lee Gresham</u>

Q. Dr. Gresham, please state your name and business address.

A. My name is Lee Gresham. My business address is 280 Melrose Street, Providence, Rhode Island, 02907.

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

A. I am employed by Rhode Island Energy as Manager of Electric Regulatory Strategy within the Gas Operations team. In this role, I am responsible for general regulatory matters, policy development, and filings, including providing strategic support to inform business decisions that advance safe, reliable, affordable natural gas distribution.

Q. Please describe your educational background and professional experience.

A. I graduated from the College of the Holy Cross with a Bachelor of Arts degree in Psychology and concentration in Pre-Medicine in 1999. In 2007, I graduated from Vermont Law School with a Juris Doctorate degree. In 2010, I received a Doctor of Philosophy degree in Engineering and Public Policy from Carnegie Mellon University. From 2010 to 2011, I was a Post-Doctoral Fellow with the Carbon Capture and Sequestration Regulatory Institute. I worked as a Senior Consultant at SAIC's Energy, Environment, and Infrastructure division from 2011 to 2012. From 2012 to 2018 I held roles of increasing responsibility as an Associate with The Brattle Group in the firm's utility practice. In 2019 I joined National Grid Service Company as a Lead Analyst for the Utility of the Future team within the Regulatory and Customer Strategy departments where I worked closely with the Massachusetts Jurisdictional President and staff, leading efforts to reduce methane and carbon emissions, developing strategies to support National Grid's objectives regarding decarbonization-related investments in the gas system, and providing testimony regarding capital investments to enable National Grid's operating companies, including Boston Gas Company d/b/a National Grid ("Boston Gas") and the former Colonial Gas d/b/a National Grid ("former Colonial Gas"), to decarbonize the gas network.

Q. Have you previously submitted testimony on behalf of Rhode Island Energy?

A. No.

__Joint Testimony__

Q. What were your roles in developing the *2024-2026 SRP Three-Year Plan*?

A. We coordinated across relevant business teams in the electric and gas businesses and led engagement with external stakeholders to develop the *2024-2026 SRP Three-Year Plan*. We additionally advised on strategy related to compliance with LCP Standards, modifications from the *2021-2023 SRP Three-Year Plan*, and addressing stakeholder questions and concerns related to the *2024-2026 SRP Three-Year Plan*.

Q. Are you sponsoring any schedules within this supplemental testimony?

A. Yes, we are sponsoring Schedule 1: Rhode Island Energy's proposed *2024-2026 System Reliability Procurement ("SRP") Three-Year Plan*.

Q. Why is Rhode Island Energy filing this joint direct testimony?

A. Rhode Island Energy is filing this joint direct testimony (1) to comply with Least-Cost Procurement ("LCP") Standards Section 4.4.E as adopted in Docket No. 23-07-EE; (2) to identify and explain proposed modifications relative to the Company's *2021-2023 SRP Three-Year Plan*; and (3) to provide context to the Rhode Island Public Utilities Commission ("Commission"), potential intervenors, and stakeholders.

Q. How is this testimony organized?

A. This testimony is organized according to the following sections:

- Section 2. Timing and relationship of near-term SRP filings
- Section 3. System reliability procurement process
- Section 4. Electric and gas system needs and optimization
- Section 5. Performance incentive plan
- Section 6. Compliance with LCP Standards
- Section 7. Request for ruling
- Section 8. Conclusion

II. <u>Timing and relationship of near-term SRP filings</u>

Q. LCP Standards Section 4.6 states "The distribution company will file the Three-Year SRP Plan on or before November 21, 2020 and triennially thereafter." Does the timing of filing of the *2024-2026 SRP Three-Year Plan* comply with LCP Standards Chapter 4.6?

A. Yes.

Q. Why is the Company filing before November 21?

A. In addition to compliance with LCP Standards, the Company is filing the *2024-2026 SRP Three-Year Plan* slightly prior to November 21 in order to coincide with the Company's filing of its *SRP Investment Proposal* for continuation of its Gas Demand Response Pilot.

Although LCP Standards Section 5.5 indicates the Commission "prefers that the [SRP investment] proposals be filed alongside, but separately from, annual Infrastructure, Safety, and Reliability Plans," which would be mid-December, filing this particular *SRP Investment Proposal* in mid-December would likely not provide sufficient time for regulatory review and approval prior to the desired start date of the Gas Demand Response Pilot, which is January 2024. Therefore, the Company is filing its *SRP Investment Proposal* for continuation of its Gas Demand Response Pilot in November, with the target of implementing the Gas Demand Response Pilot by January 2024. Since the *SRP Investment Proposal* for continuation of the Gas Demand Response Pilot was developed in alignment with the *2024-2026 SRP Three-Year Plan*, the Company thought filing the *2024-2026 SRP Three-Year Plan* concurrently would be more helpful for regulatory review than filing the *2024-2026 SRP Three-Year Plan* subsequent to the *SRP Investment Proposal*.

Q. Does the Company anticipate filing any other *SRP Investment Proposals* (besides the Gas DR Proposal) in the near term?

A. Yes, the Company anticipates filing its *SRP Investment Proposal* for Electric Demand Response alongside, but separate from, its annual *Electric Infrastructure, Safety, and Reliability Plan* in December, 2023.

Q. The Company discusses system needs for gas demand response and electric demand response, along with a potential system need for reliability in Woonsocket, in the *2024-2026 SRP Three-Year Plan* Sections 3 and 4, and includes draft *SRP Investment Proposals* in Appendix 4. Please distinguish between what's included in the *2024-2026 SRP Three-Year Plan* and what's included in the anticipated *SRP Investment Proposals.*

A. The reference to specific system needs and demand response in the sections cited from the *2024-2026 SRP Three-Year Plan* are informational and preliminary in nature; Rhode Island Energy does not request any rulings pertaining to these system needs within the *2024-2026 SRP Three-Year Plan* regulatory proceeding. Rhode Island Energy will provide requisite detail in compliance with LCP Standards Chapter 5 via *SRP Investment Proposals* filed at the appropriate time.

Q. In accordance with LCP Standards Section 6.3, did the Company collaborate with the Rhode Island Energy Efficiency and Resource Management Council ("Council") in developing the *2024-2026 SRP Three-Year Plan*?

A. Yes, the Company presented and joined discussion at the Council meetings on August 17 and October 19, 2023. The Council is also represented in the Company's SRP Technical Working Group, which engaged in the development of the *2024-2026 SRP Three-Year Plan* in May through October 2023.

Q. Did the Council vote to endorse the *2024-2026 SRP Three-Year Plan*?

A. Yes, the Council unanimously endorsed the *2024-2026 SRP Three-Year Plan* at its meeting on October 19, 2023.

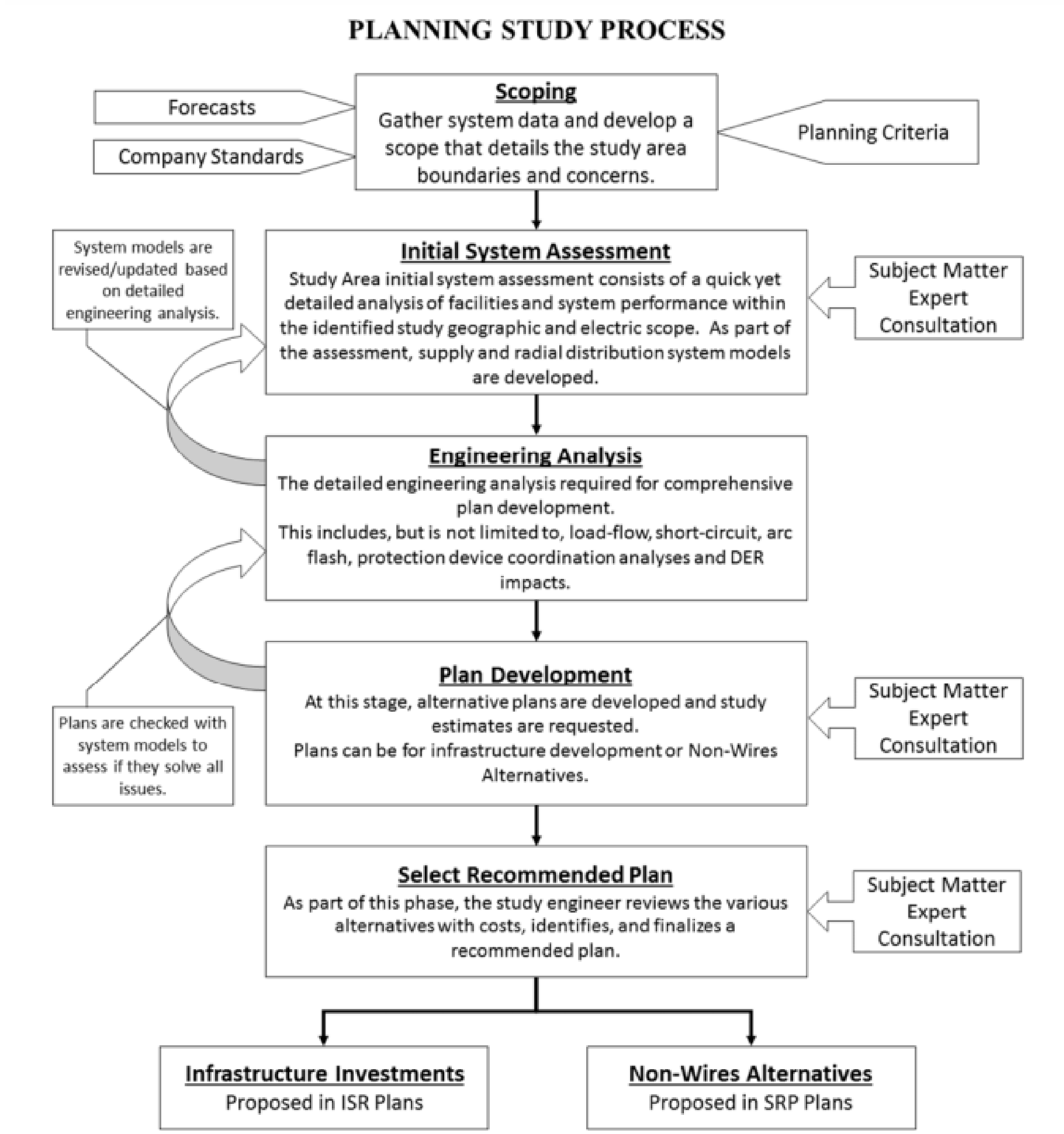
III. <u>System Reliability Procurement Process</u>

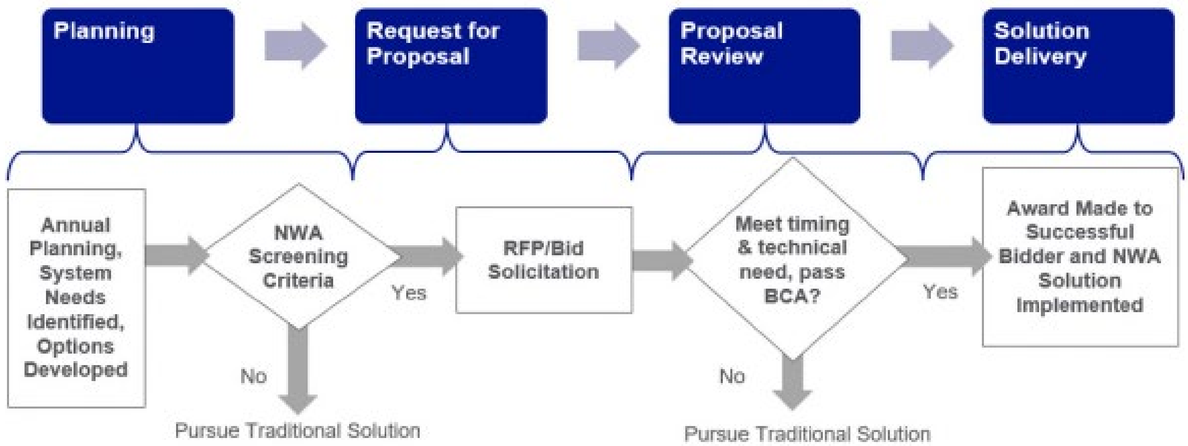
Q. What is the Company’s objective(s) in developing and describing the system reliability procurement process (Section 2 of the *2024-2026 SRP Three-Year Plan*)?

A. In addition to complying generally with LCP Standards Chapter 4, the Company’s objectives underlying the proposed system reliability procurement process are (1) evaluate potential solutions on a level playing field; (2) provide transparency to regulators, stakeholders, and the market of third-party solution providers; and (3) set forth a process that is understandable, actionable, and in clear compliance with LCP Standards.

Q. Please compare the process proposed in the *2024-2026 SRP Three-Year Plan* to the process described in the *2021-2023 SRP Three-Year Plan.*

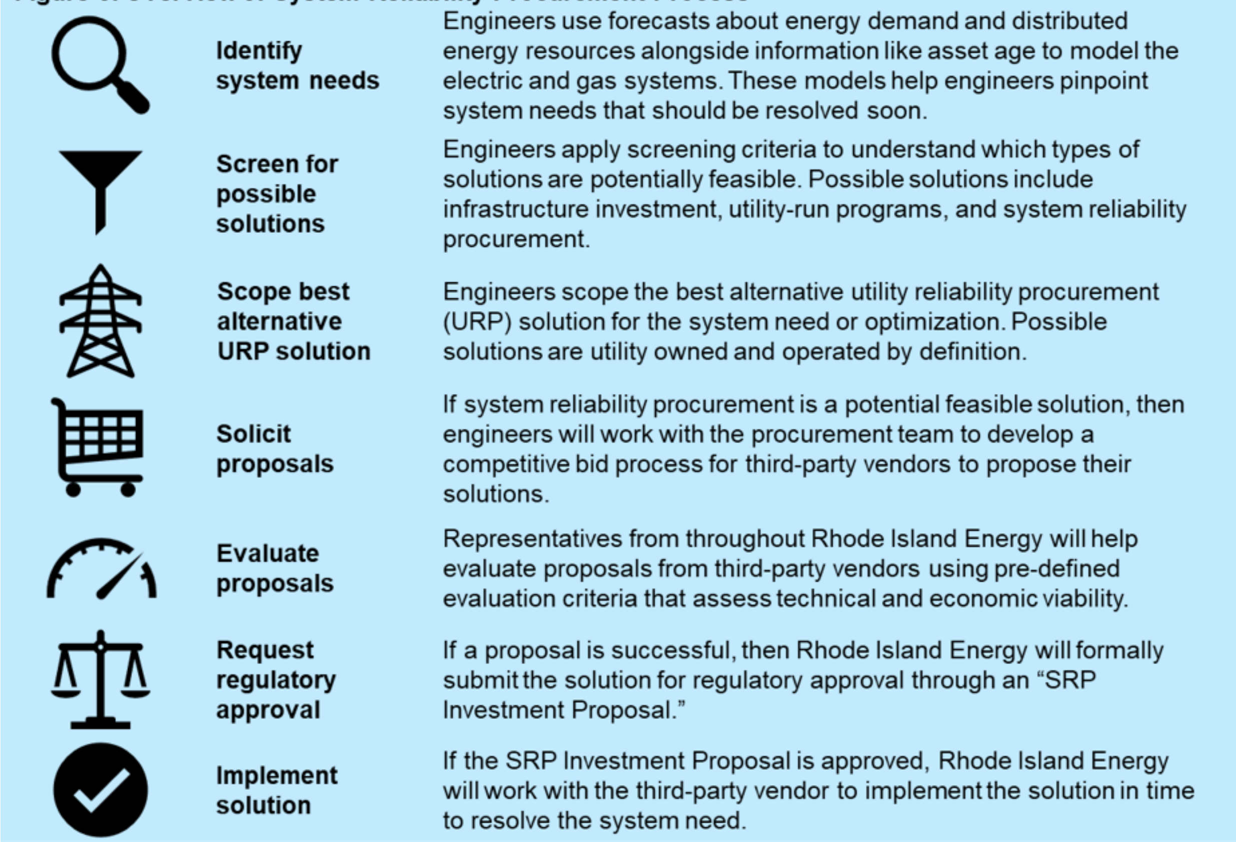
A. The *2021-2023 SRP Three-Year Plan* illustrated the system reliability procurement process using the following figures below:

1 
PLANNING STUDY PROCESS
Forecasts
Company Standards
Scoping
Gather system data and develop a scope that details the study area boundaries and concerns.
Planning Criteria
System models are revised/updated based on detailed engineering analysis.
Initial System Assessment
Study Area initial system assessment consists of a quick yet detailed analysis of facilities and system performance within the identified study geographic and electric scope. As part of the assessment, supply and radial distribution system models are developed.
Subject Matter Expert Consultation
Engineering Analysis
The detailed engineering analysis required for comprehensive plan development.
This includes, but is not limited to, load-flow, short-circuit, arc flash, protection device coordination analyses and DER impacts.
Plans are checked with system models to assess if they solve all issues.
Plan Development
At this stage, alternative plans are developed and study estimates are requested.
Plans can be for infrastructure development or Non-Wires Alternatives.
Subject Matter Expert Consultation
Select Recommended Plan
As part of this phase, the study engineer reviews the various alternatives with costs, identifies, and finalizes a recommended plan.
Subject Matter Expert Consultation
Infrastructure Investments
Proposed in ISR Plans
Non-Wires Alternatives
Proposed in SRP Plans



With the objective of improving understandability, Rhode Island Energy revised its illustration of this process to the seven steps included in the figure below for the *2024-2026 SRP Three-Year Plan*:

Figure 3. Overview of System Reliability Procurement Process



Specific differences in the proposed system reliability procurement process proposed in the *2024-2026 SRP Three-Year Plan* relative to the *2021-2023 SRP Three-Year Plan* are:

- Non-substantive clarification in terminology;
- Non-substantive revisions to the screening criteria for potential opportunities for system reliability procurement to resolve a system need or optimization;
- Non-substantive addition of notices to third-party bidders;
- Substantive revisions to the evaluation criteria used to evaluate proposals system reliability procurement solutions;

- Potentially substantive discussion about further exploration of the viability and usefulness of applying expected value to evaluation methodology; and
- Substantive inclusion of gas system reliability procurement within the system reliability procurement process.

Q. Let's discuss each change in order. Please describe the non-substantive clarification in terminology.

A. In developing the *2024-2026 SRP Three-Year Plan*, the Company and stakeholders acknowledged that 'system reliability procurement,' 'third-party solutions,' and 'non-wires solutions' were being used interchangeably yet held different meanings. To alleviate this confusion, the Company clarifies use of these terms in the *2024-2026 SRP Three-Year Plan* Section 2, Step 1. In brief, system reliability procurement encompasses utility-run and third-party-sourced non-wires and non-pipes solutions. This is consistent with the definition provided by LCP Standards Section 1.2.C.

Q. Please describe the proposed revisions to screening criteria.

A. Screening criteria is described in *2024-2026 SRP Three-Year Plan* in Section 2, Step 2. Rhode Island Energy revised the screening criteria to highlight the objectives underlying each criterion. In contrast, the screening criteria in the *2021-2023 SRP Three-Year Plan* highlighted the criterion without describing the objective for including it in the screening criteria.

For example, the screening criteria in the *2021-2023 SRP Three-Year Plan* required a system need to necessitate a solution at least $1 million in cost. The Company revised that criterion in the *2024-2026 SRP Three-Year Plan* to be “substantial enough to plausibly result in market interest” whereby a cost threshold of $1 million dollars for the wires solution is an appropriate proxy to gauge plausible market interest.

The revisions to screening criteria proposed in the *2024-2026 SRP Three-Year Plan* are not intended to be material changes to actual process, but rather clarifications of existing practice.

Q. Please describe the Company’s non-substantive addition of notices to third-party bidders.

A. The Company includes notification to third-party bidders in the *2024-2026 SRP Three-Year Plan* Section 2, Step 4 and Step 7. The intention of including these notices is to provide full transparency to third-party bidders about the expectations of cooperation and public access. The addition of these notices in the *2024-2026 SRP Three-Year Plan* does not represent a change to process.

Q. Please describe the substantive revisions to the evaluation criteria used to evaluate proposals system reliability procurement solutions.

A. The evaluation process and criteria described in the *2021-2023 SRP Three-Year Plan* was complex, including four evaluation stages and twelve evaluation criteria.[1] Rhode Island Energy updates and simplifies the evaluation process and criteria in the *2024-2026 SRP Three-Year Plan*. Specifically, the Company reduces the number of evaluation stages to two: a go/no-go evaluation of cost relative to the best alternative utility reliability procurement solution, followed by a points-driven evaluation of degree of adherence to the standards required by LCP statute and Standards (i.e., reliability, prudence, environmental responsibility, and cost-effectiveness). Whereas the *2021-2023 SRP Three-Year Plan* included twelve evaluation criteria, the Company proposes a streamlined evaluation of four criteria in the *2024-2026 SRP Three-Year Plan*. In addition to the evaluation process being more efficient, the proposed evaluation process is also more clearly structurally aligned with LCP Standards.

[1] The proposed evaluation criteria for non-pipes solutions included 14 categories in the 2021 SRP Year-End Report filed in Docket No. 5080.

Q. Please describe the Company's potentially substantive discussion about further exploration of the viability and usefulness of applying expected value to evaluation methodology.

A. The Company includes this discussion in the *2024-2026 SRP Three-Year Plan* Section 2, Step 5, with additional detail in Appendix 10. Expected valuation is a common practice for accounting for probabilities of different outcomes. Beginning in 2024, Rhode Island Energy proposes to begin exploring how to apply the concept of expected value to its evaluation of proposals for system reliability procurement. Generally, in the short-term, Rhode Island Energy proposes to apply expected value as a sensitivity analysis in situations where Rhode Island Energy conducts a benefit-cost assessment for investment choices between two alternatives, and for which it is feasible to identify potential outcomes and estimate the probabilities of those outcomes occurring. Rhode Island Energy recognizes that there may be unforeseen complexities that prevent full application of expected value and considers the next few years to be an exploratory, learning experience. Any regulatory request for ruling of a proposed investment that was influenced by the application of expected value will include comprehensive detail for further consideration and due scrutiny.

Q. Please describe the inclusion of gas system reliability procurement within the system reliability procurement process.

A. Rhode Island Energy recognizes the value of having a single process shared by both electric and gas businesses. Therefore, the Company describes a single system reliability process in the *2024-2026 SRP Three-Year Plan*. Where specific aspects of the electric and gas businesses necessitate differences in their respective system reliability procurement process, Rhode Island Energy highlights and motivates those differences. This is a change from prior SRP-related filings that considered electric and gas system reliability procurement separately.

Q. Is the gas system reliability procurement process similar to electric system reliability procurement?

A. The process for gas system reliability procurement is nearly identical to that followed for electric system reliability procurement. The identification of gas system needs and opportunities to optimize performance entails engineers using gas supply and distribution system models to perform a detailed analysis of facilities and system performance within identified geographic gas areas as well as for targeted immediate system needs. Gas engineers and the gas procurement team then discuss potential supply constraints and needs as part of the system assessment. This process prioritizes the identification of capacity-constrained areas – i.e., locations on the gas system where forecasted peak demand exceeds the amount of pipeline capacity we can rely on to be available on the coldest winter days. As with the electric system process, engineers screen for potential system reliability procurement solutions, scope the best alternative utility reliability procurement solution, then the procurement team solicits and evaluates system reliability proposals from third-party vendors. If a system reliability procurement proposal is successful, Rhode Island Energy will submit the solution for regulatory approval via an “SRP Investment Proposal” and, if approved, implement the solution.

Q. Please summarize the aspects of the system reliability procurement process that are different for gas system reliability procurement relative to electric system reliability procurement and, for each instance, please explain why the difference is necessary.

A. The gas system reliability procurement screening criteria differ from the electric system criteria in two ways. First, unlike the electric system need or optimization criteria, there is no suggested maximum placed on the load relief as a percentage of total load. This is because load removal in a capacity-constrained area poses no operational risks and instead may be necessary to alleviate the constraint. The second difference is the screening criteria for assessing gas system reliability procurement market interest: here the Company uses the guideline of a pipes solutions costing at least $0.5 million as a proxy for whether a system need is likely to gain sufficient market interest, whereas the electric system procurement guideline is $1.0 million. A lower cost threshold was chosen for gas system reliability procurement to be more inclusive of potential system reliability procurement solutions, particularly in the early stages of the non-pipes solution program to allow for greater learning. The threshold will periodically be reevaluated and revised as appropriate.

IV. Electric and gas system needs and optimizations

Q. Please summarize electric and gas system needs and optimizations identified by the Company as potential system reliability procurement opportunities in 2024 through 2026.

A. Rhode Island Energy describes three such system needs in the *2024-2026 SRP Three-Year Plan* Sections 3 and 4: electric demand response, reliability in Woonsocket, and a gas demand response pilot. The Company will continue to monitor and, if appropriate, develop these opportunities in accordance with the system reliability procurement process described in the *2024-2026 SRP Three-Year Plan* Section 2.

Q. Is the Company proposing any specific solutions or associated cost recovery for these system needs and optimizations in the *2024-2026 SRP Three-Year Plan*?

A. No, the Company is not proposing any specific solutions or associated cost recovery for these system needs and optimizations in the *2024-2026 SRP Three-Year Plan*. Any such request would progress as described in the *2024-2026 SRP Three-Year Plan* Section 2, Step 6.

Q. Could other system needs and optimizations arise that may progress either partially or completely through the system reliability procurement process?

A. Yes. As described in the *2024-2026 SRP Three-Year Plan* Section 2, Steps 1 and 2, the Company continually assesses system needs and optimization for potential solutions via system reliability procurement. Any such opportunity will progress through the system reliability procurement process as described in the *2024-2026 SRP Three-Year Plan* Section 2 and will be reported on as described in the *2024-2026 SRP Three-Year Plan* Section 7.

V. Performance Incentive Plan

Q. Please summarize the Company's proposed performance incentive plan.

A. The Company proposes performance incentive structures for (i) demand response and (ii) implementation of a system reliability procurement solution. Both incentives are structured as shared savings, where the demand response performance incentive shares avoided supply costs and system reliability procurement shares avoided distribution costs.

Q. Why does the Company propose a performance incentive at all?

A. Through system reliability procurement, Rhode Island Energy is creating value. The Company proposes to share this value between customers and shareholders, thereby accomplishing the Company's dual mission of delivering safe, affordable, reliable, sustainable energy to customers and long-term value to shareholders.

Demand Response Performance Incentive Structure

Q. What is the basis for the proposed performance incentive structure for demand response?

A. The basis for the proposed performance incentive structure for demand response is the System Efficiency Performance Incentive Mechanism developed and approved via Docket No. 4770. The Company proposes a dollar per megawatt peak reduction performance incentive for its demand response achievements in reducing regional coincident peak load. The level of incremental incentive is tied to quantitative net benefits, with the objective of sharing quantifiable cash savings with customers.

Q. Is the performance incentive structure for demand response proposed to be limited to outcomes achieved by the demand response program or could the Company earn on outcomes achieved by other activities outside of the demand response program?

A. The proposed performance incentive structure for demand response is proposed to be limited in scope to reductions in regional coincident peak load achieved by the Company's electric demand response program, branded ConnectedSolutions. This limited scope is different from the scope of the System Efficiency Performance Incentive Mechanism approved in Docket No. 4770. Any expansion of scope beyond what is proposed within the *2024-2026 SRP Three-Year Plan* would necessitate additional regulatory review.

Q. Is the demand response performance incentive tied to achievement of a specific target?

A. No. The premise of the proposed performance incentive structure for demand response is to share tangible value created. In a hypothetical case where there are no benefits realized, the Company's shareholders would receive $0. If only marginal value is realized, the Company's shareholders would receive a smaller, marginal incentive. The maximum amount of the proposed shareholder incentive is limited by the amount of benefits the Company can realize given the total program budget on an annual basis.

Q. The Company implemented a demand response program in 2023 without requiring a performance incentive. Why is a performance incentive required in 2024-2026?

A. As explained in the Company's response to PUC 1-41 in Docket No. 22-33-EE, foregoing a performance incentive was an unsustainable short-term concession to allow for the continuation of ConnectedSolutions. From the Company's response, dated November 4, 2022: "Despite the lack of incentive, the Company will continue to offer ConnectedSolutions programing in 2023. Business strategies are necessarily multi-year strategies. The Company not only has to plan for 2023 but also ensure 2023 programming paves the way for achieving core objectives in 2024 and beyond. Removing the

ConnectedSolutions program from 2023 poses risks to internal capacity and market expectations; therefore, the Company continues to propose ConnectedSolutions in 2023. The Company, however, may not offer ConnectedSolutions indefinitely without a performance incentive if, in its review of other investment options, other opportunities create greater value for customers. The current incentive level ($0) is not designed to send a regulatory signal to the Company that this program is a high priority for driving customer net benefits relative to other incentivized programs even as the Company continues to pursue ConnectedSolutions to achieve its objectives. To send appropriate signals to the Company that it should plan for and deliver the "right" amount of ConnectedSolutions programming and associated demand response in the long term, the Company recommends the program be incentivized. Without a performance incentive, the scale of demand response offered competes with all other demands for Company investment, including investments in infrastructure. A performance incentive helps to increase the priority of the program not only for financial reasons, but also aligns the Company's performance with the public interest. The "right" amount of demand response would be determined within the larger context of asset management decisions within the context of the Company's multi-year business strategy and expectations."

Q. Is the Company requesting approval for a specific value of performance incentive within the *2024-2026 SRP Three-Year Plan*?

A. No, the Company is not requesting approval of a specific value of performance incentive within the *2024-2026 SRP Three-Year Plan*. The Company is requesting approval of the performance incentive structure within the *2024-2026 SRP Three-Year Plan*.

Q. The Company proposes to share value created, with customers receiving 80 percent of value and shareholders receiving 20 percent of value. Is the Company amenable to considering other sharing schemes on a case-by-case basis?

A. Yes, the Company is amenable to considering other sharing schemes. The Company recognizes that an 80/20 percent sharing scheme may not be appropriate for all cases (e.g., if total value created is sufficiently large). The Company will propose a specific performance incentive value for future system reliability procurement investments and will evaluate and defend the proposed sharing scheme at that time.

<u>System Reliability Procurement Performance Incentive Structure</u>

Q. What is the basis of the proposed performance incentive for system reliability procurement?

A. The basis of the proposed performance incentive structure for system reliability procurement is the performance incentive structure in the *2021-2023 SRP Three-Year Plan*, whereby any cost savings of the system reliability procurement solution relative to the best alternative utility reliability procurement solution is shared between customers and shareholders in an 80-20 percent split. In contrast to the performance incentive structure from the *2021-2023 SRP Three-Year Plan*, the Company proposes a floor to the performance incentive equal to the allowed return on the best alternative utility reliability procurement solution in the *2024-2026 SRP Three-Year Plan*. This floor represents the lost earnings opportunity cost to shareholders of foregoing a utility reliability procurement solution for a system reliability procurement solution.

Q. Is the Company requesting approval for a specific value of performance incentive within the 2024-2026 SRP Three-Year Plan?

A. No, the Company is not requesting approval of a specific value of performance incentive within the *2024-2026 SRP Three-Year Plan*. The Company is requesting approval of the performance incentive structure within the *2024-2026 SRP Three-Year Plan*.

Q. Please describe the practical mechanics of evaluating, requesting, and receiving the performance incentive, if earned.

A. The value of the performance incentive would be calculated and included in the relevant *SRP Investment Proposal* for regulatory review and approval. The *SRP Investment Proposal* will also include the relevant data to assess the difference in cost (and therefore value created) between the proposed system reliability procurement solution and the best alternative utility reliability procurement solution. The specific mechanics of the performance incentive, including the timing of provision (e.g., lump sum, annualized, etc.), cost recovery mechanism, and stage gates, are dependent on the specific system reliability procurement solution (e.g., duration of deferral of best alternative utility reliability procurement solution, etc.) and, therefore, will be proposed in each *SRP Investment Proposal*. The Company is not seeking approval of those specific mechanics within the *2024-2026 SRP Three-Year Plan*.

Q. How does the proposed performance incentive plan align with the principles adopted in Docket No. 4943?

A. The Company explains how it views the proposed performance incentive to align with each principle below (principles are excerpted for easy reference).

1. A performance incentive mechanism can be considered when the utility lacks an incentive (or has a disincentive) to better align utility performance with the public interest and there is evidence of underperformance or evidence that improved performance will deliver incremental benefits.
    - Absent a performance incentive for system reliability procurement, the Company would earn less for activities that avoided infrastructure costs, which creates a natural disincentive in this dimension. A performance incentive provides the signal to align investments with public interest, whereby that public interest may include benefits of distributed energy resources in the case of system reliability procurement.

2. Incentives should be designed to enable a comparison of the cost of achieving the target to the potential quantifiable and cash benefits.
   - The proposed performance incentive plan is tied to quantifiable cash benefits; the proposed performance incentive plan does not monetize non-cash or non-quantifiable benefits. The proposed performance incentive nets the cost of the investment from the shared net quantifiable cash benefits.
3. Incentives should be designed to maximize customers' share of total quantifiable, verifiable net benefits. Consideration will be given to the inherent risks and fairness of allocation of both cash and non-cash system, customer, and societal benefits.
   - The proposed performance incentive plan is designed to maximize customers' share of total quantifiable verifiable net benefits, specifically cash benefits resulting from material avoided power system costs. The proposed performance incentive plan does not monetize non-cash system, customer, or societal benefits. The Company proposes an initial sharing scheme whereby 80 percent of value created is shared with customers and 20 percent of value is shared with shareholders; the Company is amenable to modifying this sharing scheme as appropriate on a case-by-case basis.
4. An incentive should offer the utility no more than necessary to align utility performance with the public interest.
   - Although the proposed performance incentive plan does not include a maximum earnings cap, the Company will consider how the specific performance incentive

level for a specific investment should be amended to align with this principle via the sharing scheme considered on a case-by-case basis.

5. The utility should be offered the same incentive for the same benefit. Stated another way, no action should be rewarded more than an alternative action that produces the same benefit.
    - There are currently no performance incentives for the Company to achieve benefits arising from system reliability procurement; therefore the proposed performance incentive plan does not violate this principle.

VI. Compliance with LCP Standards

Q. This section addresses each aspect of the pre-filed testimony described in LCP Standards 4.4.E. To what extent is the *2024-2026 SRP Three-Year Plan* cost-effective, prudent, reliable, environmentally responsible, and compare the cost(s) of the best alternative Utility Reliability Procurement investment(s) to the System Reliability Procurement investment(s)?

A. The *2024-2026 SRP Three-Year Plan* meets all these standards because the evaluation process proposed in Section 2, Step 5 is structured such that any system reliability procurement investment is required to meet these standards. Further review of how future proposed investments adhere to these standards will be provided in *SRP Investment Proposals* in accordance with LCP Standards Chapter 5. Rhode Island Energy discusses this alignment in detail in the *2024-2026 SRP Three-Year Plan* Section 8.

Q. In accordance with LCP Standards 4.4.E.i.b, please address issues of parity.

A. LCP Standards Chapter 3.2.M states “The distribution company shall design […] Plans to capture all resources that are cost-effective and lower cost than supply and ensure equitable access to those resources across sectors and customer classes. The distribution company shall consult with the Council to address ongoing issues of parity.”

The proposed system reliability procurement process described in the *2024-2026 SRP Three-Year Plan* Section 2 is designed to capture all resources that are cost-effective and lower cost than the best alternative utility reliability procurement solution (provided those resources are also prudent, reliable, environmentally responsible, and cost-effective) by screening each system need and optimization for the possibility of having a viable system reliability procurement solution.

The system reliability procurement process described in Section 2 and market engagement activities described in Section 5 of the *2024-2026 SRP Three-Year Plan* comprise the Company’s strategy to ensure equitable access for third-party solution providers to system reliability procurement opportunities. The system reliability procurement process is in no way dependent on or differentiated by sectors or customer classes; in this manner, the proposed system reliability procurement process ensures equitable opportunity for earning value from system reliability procurement solutions.

Rhode Island Energy has consulted with the Rhode Island Energy Efficiency and Resource Management Council ("Council") on its proposed system reliability procurement process and market engagement activities via Rhode Island Energy's System Reliability Procurement Technical Working Group and Council Meetings throughout the development of the *2024-2026 SRP Three-Year Plan*. Indeed, this engagement has resulted in the following material additions or revisions of content in the *2024-2026 Three-Year Plan*:

- The content of the Executive Summary;
- Development and clarification of the system reliability procurement process;
- The conceptual application of expected value;
- The contents of the annual report;
- Development of the performance incentive plan; and
- Topics of discussion for Rhode Island Energy's System Reliability Procurement Technical Working Group in 2024 regarding process and engagement.

VII. Request for ruling

Q. What approvals for the *2024-2026 SRP Three-Year Plan* is the Company requesting from the Commission?

A. Rhode Island Energy lists its requests for ruling in the *2024-2026 SRP Three-Year Plan* Section 9. In accordance with LCP Standards Section 4.5, Rhode Island Energy respectfully requests that the Commission

A. Approve screening requirements and implementation plans described in the *2024-2026 SRP Three-Year Plan* Sections 2-5;

B. Approve annual reporting requirements described in the *2024-2026 SRP Three-Year Plan* Section 7; and

C. Approve the performance incentive plan described in the *2024-2026 SRP Three-Year Plan* Section 6.

Please note that Rhode Island Energy is not requesting any ruling on the draft System Reliability Procurement Investment Proposals contained in the *2024-2026 SRP Three-Year Plan* Appendix 4 at this time; final versions of these proposals will be filed with the Commission for review and approval separately.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes, it does.

The Narragansett Electric Company
d/b/a Rhode Island Energy

2024-2026 System Reliability Procurement (SRP) Three-Year Plan

November 17, 2023

Submitted to:

Rhode Island Public Utilities Commission in
RIPUC Docket No. 23-47-EE

Prepared by:

Rhode Island Energy™
a PPL company

Contents

Executive Summary

System Reliability Procurement (SRP) encompasses the activities conducted by The Narragansett Electric Company d/b/a Rhode Island Energy to meet or mitigate a gas or electric system need or optimization that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[1] In this *2024-2026 SRP Three-Year Plan* ("Plan"), Rhode Island Energy summarizes its proposed implementation plan for system reliability procurement. This Executive Summary is intended to provide a high-level overview.

How does Rhode Island Energy identify opportunities for system reliability procurement?
Rhode Island Energy's system planners identify opportunities for system reliability procurement as they identify and screen system needs. The figure below describes the entire system reliability procurement process from identifying system needs to implementing system reliability procurement solutions. Section 2 describes this process in detail, and Sections 3 and 4 identify opportunities for system reliability procurement solutions in the queue.

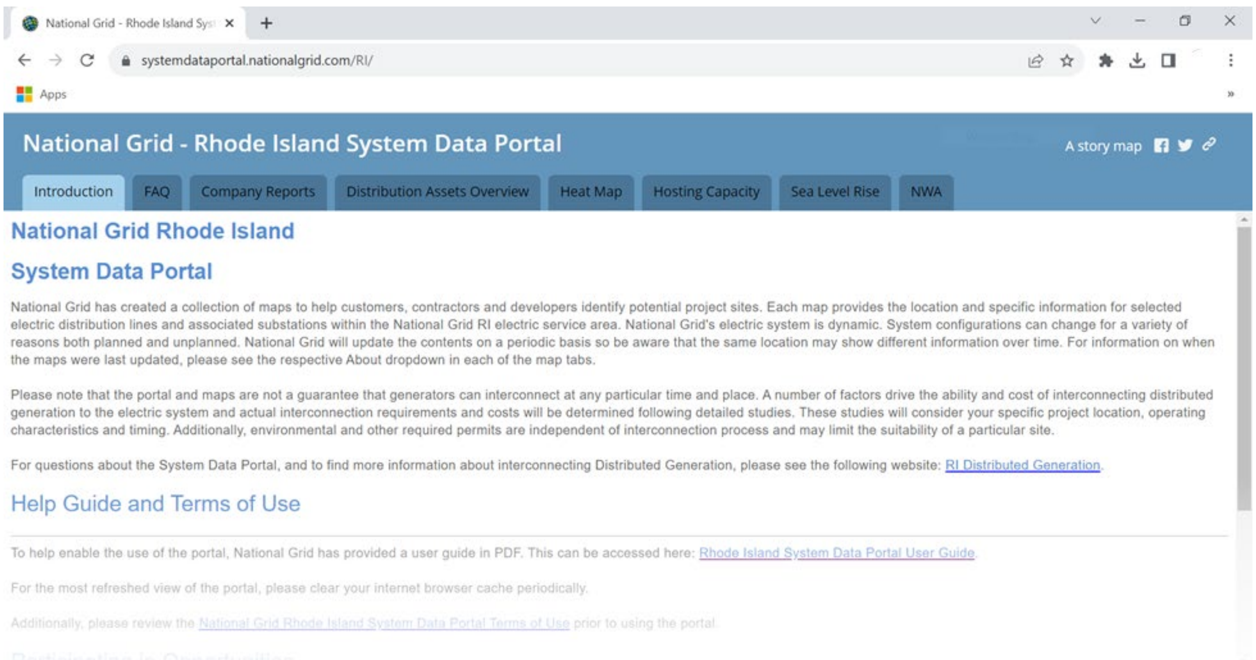
Figure ES-1. Overview of System Reliability Procurement Process

Identify system needs	Engineers use forecasts about energy demand and distributed energy resources alongside information like asset age to model the electric and gas systems. These models help engineers pinpoint system needs that should be resolved soon.
Screen for possible solutions	Engineers apply screening criteria to understand which types of solutions are potentially feasible. Possible solutions include infrastructure investment, utility-run programs, and system reliability procurement.
Scope best alternative URP solution	Engineers scope the best alternative utility reliability procurement (URP) solution for the system need or optimization. Possible solutions are utility owned and operated by definition.
Solicit proposals	If system reliability procurement is a potential feasible solution, then engineers will work with the procurement team to develop a competitive bid process for third-party vendors to propose their solutions.
Evaluate proposals	Representatives from throughout Rhode Island Energy will help evaluate proposals from third-party vendors using pre-defined evaluation criteria that assess technical and economic viability.
Request regulatory approval	If a proposal is successful, then Rhode Island Energy will formally submit the solution for regulatory approval through an "SRP Investment Proposal."
Implement solution	If the SRP Investment Proposal is approved, Rhode Island Energy will work with the third-party vendor to implement the solution in time to resolve the system need.

[1] Per the Rhode Island Public Utilities Commission's Least-Cost Procurement Standards, 2023 version.

How can third-party solution providers find opportunities to propose solutions?

Third-party solution providers can find opportunities for system reliability procurement via Rhode Island Energy's System Data Portal, available here: https://systemdataportal.nationalgrid.com/RI/.[2] Specifically, third-party solution providers can access open solicitations for system reliability procurement solutions using the *NWA* tab and can follow along with Rhode Island Energy's system planning by viewing the area studies; system reliability procurement plans; and infrastructure, safety, and reliability plans in the *Company Reports* tab. Section 5 includes additional discussion of planned updates and improvements to the System Data Portal. Appendix 5 contains a helpful user guide to assist users in getting the most out of the System Data Portal.



How can stakeholders engage?

In the spirit of transparency and continuous improvement, Rhode Island Energy welcomes stakeholder engagement through the following channels:

- ✓ Third-party solution providers can add their contact information to Rhode Island Energy's distribution lists for solicitations; these distribution lists may also be used for other communications to solicit feedback from third parties on system reliability procurement processes (email cagill@rienergy.com to be added to distribution lists).
- ✓ Stakeholders representing customer, third party, or other interests can engage directly with Rhode Island Energy (email cagill@rienergy.com to discuss the most productive way to engage).

[2] Please note that Rhode Island Energy is in the process of transitioning the System Data Portal from prior parent company National Grid; users should expect branding and company identification to transition during 2023-2024.

- ✓ Anyone (third-party solution providers, stakeholder groups, customers, etc.) can follow along with and engage via the Rhode Island Energy Efficiency and Resource Management Council (EERMC); visit the EERMC's website to learn more about the EERMC's oversight role in system reliability procurement and identify meetings to attend and ways to engage: www.rieermc.ri.gov.
- ✓ Anyone (third-party solution providers, stakeholder groups, customers, etc.) can follow along with and engage as appropriate in regulatory proceedings; visit the Rhode Island Public Utilities Commission's website to access dockets related to system reliability procurement: www.ripuc.ri.gov.
- ✓ Just have a general question or thought? Email Carrie Gill at cagill@rienergy.com to discuss.

<u>How is SRP coordinated across other distribution system planning and investment activities?</u>
Rhode Island Energy conducts a number of business activities in the pursuit of delivering safe, affordable, reliable, and sustainable energy to our customers. As such, teams throughout Rhode Island Energy coordinate to make sure all investments and customer programs are aligned to make the most effective impacts. The table below provides some detail about how Rhode Island Energy coordinates between system reliability procurement and other distribution system planning and investment activities.

Infrastructure, Safety, and Reliability Planning	All distribution system planning, whether it results in utility reliability procurement that proceeds through *Infrastructure, Safety, and Reliability Plans* or system reliability procurement, begins with identifying system needs using forecasts about energy demand and distributed energy resources alongside information like asset age to model the electric and gas systems. Coordination between utility reliability procurement and system reliability procurement is inherent to Rhode Island Energy's internal structure of identifying system needs and ensures no duplication of efforts.
Energy Efficiency	System reliability procurement and energy efficiency are both authorized through Rhode Island's Least-Cost Procurement Statute and further stipulated through regulatory standards. Rhode Island Energy's energy efficiency team will propose the viability of targeted energy efficiency in response to open solicitations for system reliability procurement, to be evaluated alongside proposals third-party solution providers. In particular, demand response programs (conducted as system reliability procurement) overlay performance incentives on purchase and financing incentives accessed through energy efficiency programs. Staff are fully coordinated on leveraging both incentive streams to maximize demand response program impacts.
Customer Communications	Rhode Island Energy's customer communications team is fully integrated into outreach and engagement for system reliability procurement during the 2024-2026 period. Outreach and engagement could include open solicitations for system reliability procurement, awareness of the System Data Portal, education and volunteer peak demand reduction for ConnectedSolutions, and other information related to system reliability procurement activities, as appropriate.

Grid Modernization and Advanced Metering	Rhode Island Energy has filed proposals with the Rhode Island Public Utilities Commission to transition to advanced metering (Docket No. 22-49-EL) and modernize the electric grid (Docket No. 22-56-EL), both of which are ongoing proceedings as of September 1, 2023. Regardless of the outcomes of either proceeding, system reliability procurement will continue and Rhode Island Energy will continue to screen system needs for the possibility of having system reliability procurement solutions, for which Rhode Island Energy would solicit proposals. Indeed, enhanced visibility, communications, and control achieved through advanced metering and grid modernization would benefit Rhode Island Energy's ability to forecast system needs and employ system reliability procurement solutions.
Last Resort Service Supply Procurement	Through a RI PUC approved procurement process, Rhode Island Energy procures energy supply on behalf of all customers who have chosen not to receive supply from an alternate supplier (i.e. retail or competitive supplier). Rhode Island Energy's procurement team is involved in informing decisions about the scale of peak reduction targeted through demand response activities within system reliability procurement.

For more information…

The following *2024-2026 SRP Three-Year Plan* describes Rhode Island Energy's vision for system reliability procurement throughout 2024-2026. Interested stakeholders, third-party solution providers, and energy system enthusiasts are encouraged to read on to learn more about Rhode Island Energy's system reliability procurement processes, upcoming activities and programs, regulatory compliance, and additional technical and conceptual details.

Section 1. Introduction

System Reliability Procurement (SRP) encompasses the activities conducted by The Narragansett Electric Company d/b/a Rhode Island Energy to meet or mitigate a gas or electric system need or optimization by employing diverse energy resources, distributed generation, or demand response.[3] In this *2024-2026 SRP Three-Year Plan ("Plan")*, Rhode Island Energy summarizes its proposed implementation plan for system reliability procurement.

The Rhode Island Public Utilities Commission provides principles for the design of each Three-Year Plan in their Least-Cost Procurement Standards, shown in Figure 1.

In designing this Plan, Rhode Island Energy translated the principles in Figure 1 to a set of four objectives and strategized how to build these objectives into the Plan. Figure 2, next page, connects principles A through C from Figure 1 to these objectives and actions. This figure was discussed with the SRP Technical Working Group on May 17, 2023, and the Energy Efficiency and Resource Management Council on May 18, 2023.[4]
Throughout this Plan, we include several figures and tables to aid in understanding and clarity. Figures with a blue background apply generally to the electric and gas systems. Figures with a yellow background provide definitions or other regulatory, statutory, or policy citations. Figures with a teal background are specific to the electric system. Figures with a purple background are specific to the gas system. The objective of this color coding is to assist readers in navigating this Plan.

Figure 1: General Plan Design and Principles

A. In order to meet Rhode Island's gas and electric energy system needs and policy goals in a manner consistent with R.I. Gen. Laws §39-1-27.7, Three-Year SRP Plans should include both a broad consideration of needs and goals and broad consideration of solutions to these needs and goals in order to encourage optimal investment by the distribution company.

B. The Three-Year SRP Plan should be integrated with the distribution company's distribution planning process and be designed, where possible, to complement the objectives of Rhode Island's energy policies and programs as described in Section 3.2.A.

C. The Three-Year SRP Plan should be designed so that potential non-utility solution providers can understand how and when the distribution company makes decisions to implement System Reliability Procurement in lieu of Utility Reliability Procurement.

Source: Least-Cost Procurement Standards, Section 4.3 (Docket No. 23-07-EE)

---

[3] Rhode Island Public Utilities Commission's Least-Cost Procurement Standards (Docket 23-07-EE).
[4] For more information about the SRP Technical Working Group, see Section 5. To date, the *2024-2026 SRP Three-Year Plan* was discussed with the SRP TWG on May 17 and July 19, and with the Energy Efficiency and Resource Management Council on May 18.

Figure 2. RIE Priorities for the 2024-2026 SRP Three-Year Plan

A	B	C	Objectives	How
		√	**Readable**: Easy to navigate and understand by any reader, including third-party solution providers	• Restructuring sections and content to be more responsive to the LCP Standards Chapter 4 • Organizational discipline • Concise writing, figures
√	√		**Useful**: Demonstrate clear alignment and integration with other business functions and investment proposals	• Links to overarching business objectives • Cross references • Calling out contingencies if/when they exist
√		√	**Actionable**: Where we identify areas of innovation or improvement, provide clear and actionable workplans	• Work/research/discussions needed • Milestones • Interim and end deliverables • Eval process for internal EE/DR/etc efforts
√	√	√	**Compelling**: Clear proposals for PUC ruling with well-supported justification and reasoning	• Screening requirements and implementation plans for non-wires and non-pipes solutions • Annual reporting requirements • Performance metrics and incentive plan • Other proposals, as appropriate

Contents

This Plan is organized into sections aligned with required content as described in Chapter 4.4 of the Least-Cost Procurement Standards. Non-wires solutions and non-pipes solutions are each addressed throughout each of the sections of this Plan. The appendices to this Plan provide additional details to aid in understanding of the Report and to comply with legal and regulatory reporting requirements.

Appendices

Section 2. System Reliability Procurement Process

Overview

In this Section, Rhode Island Energy describes the system planning process, from identification of system needs, screening for system reliability procurement, and procuring, evaluating, and implementing solutions.

We describe each step in detail. Although many steps are the same regardless of whether the system need or optimization is for the electric or gas system, there are some steps in which we handle electric system needs differently from gas system needs. We take care in pointing out these differences and explain why these differences are appropriate within our pre-filed testimony.

Figure 3 summarizes the system reliability procurement process as a sequence of high-level steps. These high-level steps are fully integrated into the overall electric and gas system planning processes. We walk through each of these steps in order in the following subsections, and discuss report-outs on the results of each step within Section 7: Annual Reporting.

Figure 3. Overview of System Reliability Procurement Process

Identify system needs	Engineers use forecasts about energy demand and distributed energy resources alongside information like asset age to model the electric and gas systems. These models help engineers pinpoint system needs that should be resolved soon.
Screen for possible solutions	Engineers apply screening criteria to understand which types of solutions are potentially feasible. Possible solutions include infrastructure investment, utility-run programs, and system reliability procurement.
Scope best alternative URP solution	Engineers scope the best alternative utility reliability procurement (URP) solution for the system need or optimization. Possible solutions are utility owned and operated by definition.
Solicit proposals	If system reliability procurement is a potential feasible solution, then engineers will work with the procurement team to develop a competitive bid process for third-party vendors to propose their solutions.
Evaluate proposals	Representatives from throughout Rhode Island Energy will help evaluate proposals from third-party vendors using pre-defined evaluation criteria that assess technical and economic viability.
Request regulatory approval	If a proposal is successful, then Rhode Island Energy will formally submit the solution for regulatory approval through an "SRP Investment Proposal."
Implement solution	If the SRP Investment Proposal is approved, Rhode Island Energy will work with the third-party vendor to implement the solution in time to resolve the system need.

Step 1. Identify System Needs and Optimization

The Rhode Island Energy team identifies system needs and opportunities to optimize system performance through routine distribution system planning studies, through annual distribution system planning processes, and through annual consideration of supply-related needs and opportunities.

Electric System

Engineers use electrical models to simulate conditions on the electric system, given inputs like forecasted load growth, forecasted penetration of distributed energy resources, and characteristics of electric assets, like age. These models help engineers pinpoint system issues and when they need to be addressed. Engineers do this type of planning every several years for geographical electrical areas (called area studies) and annually for targeted immediate system needs.

Engineers and supply procurement team members will also discuss potential supply constraints or needs on an annual basis. Rhode Island and the region typically experience peak supply demand on hot summer evenings, which can result in higher supply costs for customers. The team considers high supply costs as an opportunity for optimization of system performance.

Figure 4. Definitions

Electric System Needs
Needs to serve both customer load and customer generation, including, but not limited to, system capacity (normal and emergency), voltage performance, reliability performance, protection coordination, fault current management, reactive power compensation, asset condition assessment, distributed generation constraints, operational considerations, and customer requests.

Gas System Needs
Needs to serve customers, including, but not limited to, system capacity (normal and emergency), pressure management, asset condition assessment, gas service that supports electric distributed generation, and operational considerations.

Optimization of System Performance
Improvement of the performance and efficiency of the gas or electric system that includes enhanced reliability, peak load reduction, improved utilization of both utility and non-utility assets, optimization of operations, and reduced system losses.

Source: Least-Cost Procurement Standards (2023 version)

Gas System

The process of identifying gas system needs and opportunities to optimize performance is very similar to that followed for electric system planning. Engineers use gas supply and distribution system models to perform a detailed analysis of facilities and system performance within identified geographic gas areas as well as for targeted immediate system needs. Gas engineers and the gas procurement team discuss potential supply constraints and needs as part of the system assessment. This process prioritizes the identification of capacity-constrained areas – i.e., locations on the gas system where forecasted peak demand exceeds the amount of pipeline capacity we can rely on to be available on the coldest winter days.

Step 2. Screen for Possibility of System Reliability Procurement Solution

Once a system need or opportunity for system optimization is identified, the Rhode Island Energy team screens for the possibility that a system reliability procurement solution may be technically and economically viable.

Figure 5, below, defines the two categories of possible solutions to a system need or optimization: system reliability procurement solutions with utility reliability procurement solutions.

Figure 5. Definitions

Utility Reliability Procurement

Procurement to meet or mitigate a gas or electric distribution system need or optimization that is not System Reliability Procurement and thus represents a utility-only investment or expenditure.*

* For example, many such Utility Reliability Procurement investments and operations are proposed in annual Infrastructure, Safety, and Reliability Plans filed pursuant to R.I. Gen. Laws § 39-1-27.7.1(c)(2).

System Reliability Procurement

Procurement to meet or mitigate a gas or electric distribution system need or optimization from a party other than the gas or electric utility** that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.***

** A utility proposal to own and operate non-traditional investment or new operations and maintenance services, such as new voltage-regulation equipment, battery storage, or vegetation management, and any vendor services associated with such investment or service, shall not be considered System Reliability Procurement per this definition. Such investments and services are, however, still subject to the Guidance Document issued in Docket No. 4600A.

*** Including, but not limited to, the resources named in R.I. Gen. Laws § 39-1-27.7(a)(1)(i)-(iii).

Source: Least-Cost Procurement Standards (2023 version)

Figure 6, below, compares and contrasts key terminology that describes various possible solutions to assist with understanding.

System reliability procurement encompasses solutions proposed by third-party vendors and solutions operated by Rhode Island Energy. However, utility reliability procurement is limited to solutions owned and operated by Rhode Island Energy.

System reliability procurement only encompasses non-wires and non-pipes solutions. Utility reliability procurement can encompass both wires/pipes solutions and non-wires/non-pipes solutions.

Note that this step is technology agnostic; screening criteria for the possibility of a system reliability procurement solution to a system need or optimization are silent on technology alternatives.

Figure 6. Examples of Solutions and Relevant Terminology

	Wires/Pipes Solutions	**Non-Wires/ Non-Pipes Solutions**
Utility Reliability Procurement (URP)	Reconductoring Upsize transformers Pipe replacement	Utility-owned and operated battery storage CVR/VVO
System Reliability Procurement (SRP)	Not applicable	***Utility-run*** or ***third-party*** demand response or targeted energy efficiency ***Third-party*** owned and operated battery storage

Electric System Screening Criteria

Engineers screen system needs for the potential viability of a system reliability procurement solution. This screening is fully integrated into the planning process and is part of the normal course of business.

Screening criteria are described in Figure 7, below. These screening criteria are applied by the engineering team to all electric system needs and opportunities for optimizing system performance that arise during Step 1.

System needs that fail any of the screening criteria will be proposed as "wires solutions" through Rhode Island Energy's annual *Electric Infrastructure, Safety, and Reliability ("ISR") Plan* at the appropriate time.

System needs that pass the screening then advance through the following steps to solicit and evaluate the viability of system reliability procurement solutions.

Figure 7. Screening Criteria for Non-Wires Solutions through System Reliability Procurement

Not an asset condition issue

Electric assets that have reached the end of their lifetimes need to be replaced; a non-wires solution (whether system reliability or utility reliability procurement) cannot resolve an asset condition issue.

Eligible system need or optimization

Eligible system needs and optimization include load relief, reliability, and supply cost mitigation. If the system need is load relief, the amount of load should not exceed 20% of total load in the area of the defined need.

Sufficient Market Interest

The system need or optimization must be substantial enough to plausibly result in market interest. Rhode Island Energy uses a guideline of the wires solution costing at least $1 million as a proxy for whether a system need is likely to gain sufficient market interest.

Adequate time to implement

There must be at least 24 months before the start date of non-wires solution implementation to allow adequate time to go to market, evaluate proposals, gain necessary approvals, and construct or deploy the proposed non-wires solution.

Additionally, by the Company's discretion, Rhode Island Energy may pursue a project that does not pass one or more of these screening criteria if there is reason to believe that a viable non-wires solution exists, assuming the benefits of doing so justify the costs.

Gas System Screening Criteria

Gas system reliability procurement is a nascent program and process, requiring ongoing development so that full integration into the gas planning process and normal course of business can be achieved. As with the electric system, the objective is for gas engineers to screen system needs for the potential viability of a system reliability procurement solution. Given the emergent nature of the program, we anticipate the screening process and criteria may evolve, informed by experience and learnings. Any proposed changes will be submitted for regulatory approval per LCP Standards at the appropriate time.

Once embedded in the gas planning process, screening criteria will be applied by the engineering team to system needs and opportunities for optimizing system performance that arise during Step 1. Screening criteria for the gas system are described in Figure 8, below.

System needs that fail any of the screening criteria will be proposed as "pipes solutions" through Rhode Island Energy's annual *Gas Infrastructure, Safety, and Reliability ("ISR") Plan* at the appropriate time.

System needs that pass the screening then advance through the following steps to solicit and evaluate the viability of system reliability procurement solutions. Projects that meet the screening criteria will be prioritized in consideration of capacity-constrained areas on the gas system.

Figure 8. Screening Criteria for Non-Pipes Solutions through System Reliability Procurement

Not an asset replacement investment

Gas assets that pose immediate, local, and system-wide safety and/or reliability impacts must be replaced; a non-pipes solution (whether system reliability or utility reliability procurement) cannot resolve a critical safety or reliability issue.

Eligible system need or optimization

Eligible system needs and optimization include load reduction, load removal, and supply constraint mitigation.

Sufficient Market Interest

The system need or optimization must be substantial enough to plausibly result in market interest. Rhode Island Energy uses a guideline of the pipes solution costing at least $0.5 million as a proxy for whether a system need is likely to gain sufficient market interest.

Adequate time to implement

There must be at least 24 months before the start date of non-pipes solution implementation to allow adequate time to go to market, evaluate proposals, gain necessary approvals, and construct or deploy the proposed non-pipes solution.

Additionally, by the Company's discretion, Rhode Island Energy may pursue a project that does not pass one or more of these screening criteria if there is reason to believe that a viable non-pipes solution exists, assuming the benefits of doing so justify the costs.

<u>Step 3. Scope the Best Alternative Utility Reliability Procurement Solution</u>
Least-Cost Procurement Standards require "System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement" (Section 1.3.A). Therefore, we first must understand what the best alternative utility reliability procurement solution is.

System engineers always develop their recommendation for the best utility reliability procurement solution. These solutions are described in area studies and annual *Infrastructure, Safety, and Reliability ("ISR") Plans*.

For any system need or optimization that passes the screening criteria in Step 2 of the system reliability procurement process, the cost of the best alternative utility reliability procurement solution will be denoted as the cost against which to compare system reliability procurement proposals.

Step 4. Solicit Proposals

Rhode Island Energy will solicit proposals for all possible solutions identified, whether from a third-party vendor or an internal business functional team (i.e., utility-run non-wires/non-pipes solutions).

Solicitation will occur via a competitive Request for Proposals ("RFP"). Internally, a procurement specialist will work with engineers and others to develop the RFP, which will fully detail the scope of the system need or opportunity for optimization. The RFP will include all technical specifications required to design a solution. Each RFP will have a period during which potential bidders can ask additional questions.

Rhode Island Energy may require a two-stage proposal process, where the first stage requires a letter of intent describing the proposed concept prior to the second stage proposal with complete technical and financial detail. The objective of this two-stage proposal process is to reduce workload and improve proposals by providing an opportunity for Rhode Island Energy to give feedback and express interest (non-interest) in technically viable (non-viable) proposals.

Results of solicitations – including information about third-party and internally-sourced proposals received – will be reported annually; see Section 7 for more information.

Proposals for Third-Party Solutions

Third-party solution providers may submit proposals for non-wires and non-pipes solutions. RFPs will be posted publicly and can be found by navigating to Rhode Island Energy's System Data Portal.[5] Rhode Island Energy will conduct outreach for each RFP to engage the market in the objective of obtaining a robust set of competitive proposals. Rhode Island Energy will include comprehensive instructions for how potential bidders can submit questions and proposals.

[5] See Section 5 for more information about Rhode Island Energy's System Data Portal.

Notice to Third-Party Bidders

To aid in transparent processes, the following will be included in each RFP:

> *"All proposals received by Rhode Island Energy ("RIE") in connection with this Request for Proposals ("RFP") are subject to public disclosure, specifically through filings made by RIE with the Rhode Island Public Utilities Commission ("PUC"). Filings with the PUC are subject to the Rhode Island Access to Public Records Act ("APRA"), R.I. Gen. Laws §38-2-1, et. seq. When making filings with the PUC, RIE will consider all proposals to be public unless RIE, in its discretion, finds that certain portions of information contained within the proposals are exempt from public disclosure pursuant to R.I. Gen. Laws §38- 2-2(4), in which case, RIE may seek confidential treatment from the PUC. Offerors are advised to clearly mark or label "confidential" any portions of information within their proposals that they believe are "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature." When making a filing with the PUC, RIE will take into consideration any information marked by the offeror as confidential. However, broad disclaimers that label the entire proposal as confidential will not help RIE in its APRA analysis and may not be considered."*

Proposals for Utility-Run Solutions

Program leads representing possibly viable utility-run solutions (i.e., energy efficiency, demand response, renewable energy programs, and energy storage) will be asked to develop proposals in response to the same RFP used to solicit proposals from third-party vendors, subject to the same deadlines, processes, and transparency standards.

<u>Step 5. Evaluate Proposals</u>

With the objective of comparing possible solutions on a level playing field, all possible solutions – whether utility-run or third-party provided – are pursued and evaluated in parallel.

First, the procurement specialist will review all proposals to ensure their completeness. On a case-by-case basis, the procurement specialist may notify bidders of incomplete proposals and allow time for bidders to remedy their proposals. Bidders who do not or cannot submit complete proposals will be notified of their disqualification from the procurement process. The procurement specialist will share all complete proposals with members of the Rhode Island Energy evaluation committee, who will be determined prior to issuing the RFP.

All proposals will be evaluated by all members of the evaluation committee using the same evaluation sequence, evaluation criteria, and weighting. Each member will score each proposal; all member scores will be averaged to obtain the final score. The proposal with the highest score will be tentatively selected; all other bidders will be notified of non-selection.

Evaluation criteria is defined and described in the Least-Cost Procurement Standards, Section 1.3.A:

> *"Least-Cost Procurement shall be cost-effective, reliable, prudent, and environmentally responsible. ... System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement."*

Rhode Island Energy adopts these criteria in its evaluation rubric, shown in Figure 8, below. As a threshold step, any proposal that costs more than the best alternative utility reliability procurement solution identified in Step 3 will be removed from consideration. Rhode Island Energy will conduct its comparison of costs using the stipulations defined in Least-Cost Procurement Standards Section 1.3.H.[6]

The evaluation committee will review all remaining proposals and score them based on the extent to which they are cost-effective, reliable, prudent, and environmentally responsible. Rhode Island Energy will conduct its evaluation consistent with the requirements provided by the Least-Cost Procurement Standards in Section 1.3, including adherence to the principles for cost tests and resource assessments in Standards Section 1.3.B.[7] Using the stipulations defined in Least-Cost Procurement Standards Sections 1.3.C, 1.3.D, 1.3.E, and 1.3.F, any proposal that is found to be not cost-effective, reliable, prudent, or environmentally responsible will be removed from consideration.[8]

---

[6] "Lower than the cost of the best alternative Utility Reliability Procurement i. The distribution company shall compare the cost of System Reliability Procurement measures, programs, and/or portfolios to the cost of the best alternative Utility Reliability Procurement option using all applicable costs enumerated in the RI Framework. The distribution company shall provide specific costs included in the Cost of System Reliability Procurement. ii. At a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test. iii. The distribution company shall describe which costs in the RI Framework were included in the cost of System Reliability Procurement and which costs are included in the alternative Utility Reliability Procurement. For any categories that are not included in either, the distribution company shall describe why these categories are not included."

[7] Least-Cost Procurement Standards Section 1.3.B: "When preparing any cost test or resource assessment, including the RI Test, the following principles will be applied: i. Supply-side and demand-side alternative energy resources shall be compared in a consistent and comprehensive manner. ii. Cost tests shall be created using the RI Framework and account for applicable policy goals, as articulated in legislation, PUC orders, regulations, guidelines, and other policy directives. iii. Cost tests shall account for all relevant, important impacts, even those that are difficult to quantify and monetize. Where applicable cost or benefit categories cannot be quantified, such categories shall be qualitatively assessed.8 iv. Cost tests shall be symmetrical, for example, by including both costs and benefits for each relevant type of impact. v. Analyses of the impacts of investments shall be forward-looking, capturing the difference between costs and benefits that would occur over the life of the investments with those that would occur absent the investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis. vi. Cost tests shall be completely transparent and should fully document and reveal all relevant inputs, assumptions, methodologies, and results."

[8] The full reference to Least-Cost Procurement Standards Section 1.3 is included in Appendix 3 for easy reference.

Of all remaining proposals, Rhode Island Energy will tentatively select the proposal with the highest score for continuation in the system reliability procurement process. Outcomes of evaluations – including evaluations of third-party and internally-sourced proposals – will be reported annually; see Section 7 for more information.

Figure 8. System Reliability Procurement Evaluation Rubric

Criteria	Description	Weight
Cost	Total project cost is less than or equal to cost of best alternative Utility Reliability Procurement	Go/No-Go
Cost-Effective	Using the Docket 4600 Benefit-Cost Framework, to what extent do benefits outweigh costs?	25; No-Go if BCR- < 1.0
Reliable	To what extent can the proposal reliably resolve the system need?	25; No-Go if deemed not reliable
Prudent	To what extent would advancing the proposal be considered a prudent decision?	25; No-Go if deemed not prudent
Environ-mentally Respon-sible	To what extent is the proposal environmentally responsible?	25; No-Go if not environ-mentally responsible
	Total	**100**

Expected Value

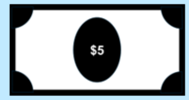
Beginning in 2024, Rhode Island Energy will begin exploring how to apply the concept of expected value to its evaluation of proposals for system reliability procurement.

What is expected value?

Expected valuation is a common practice for accounting for probabilities of different outcomes. In essence, the expected value of an action is the sum of its probability-weighted values (see Figure 9).

Expected value may be applied when there are multiple possible outcomes that may result from an action. By applying expected value, we can appropriately internalize the range of likely outcomes; not applying expected value may result in over-emphasizing (under-emphasizing) a particular outcome because of the implicit assumption that outcome will result with 100% (0%) certainty.[9]

Figure 9. Simple illustration of expected value



99% probability of winning $5
(0.99 X $5.00 = $4.95)

PLUS

1% probability of winning $100
(0.01 X $100.00 = $1.00)

EQUALS

Expected Value of $5.75

If you were to assume winning $5 were the only outcome, then you'd be implicitly assuming 100% probability of winning $5 and 0% probability of winning $100, for an expected value of $5.

If you had to buy a lottery ticket to access these winnings, an economically rational person would be willing to pay up to $5.75 to take the bet that recognizes the small, but non-zero chance of winning $100; up to $0.75 more than an economically rational person who considers only 100% chance of winning $5.

When to apply expected value?

Generally, in the short-term, Rhode Island Energy will apply expected value as a sensitivity analysis in situations where Rhode Island Energy conducts a benefit-cost assessment for investment choices between two alternatives, and for which it is feasible to identify potential outcomes and estimate the probabilities of those outcomes occurring. Rhode Island Energy recognizes that there may be unforeseen complexities that prevent full application of expected value and considers the next few years to be an exploratory, learning experience.

As a first step in this learning experience, Rhode Island Energy will first apply expected value to investment decisions regarding non-wires (non-pipes) solutions relative to wires (pipes) solutions, where the potential outcomes differ in the length of the deferral term of the wires (pipes) solution.

In the longer-term, Rhode Island Energy can potentially apply expected value to more complex decisions, including but not limited to decisions between more than two alternatives and decisions with more than two potential outcomes.

[9] For more information about expected valuation, see Appendix 10.

Whenever Rhode Island Energy applies expected value, Rhode Island Energy will document the exact method for each step contained in the methodology, all assumptions, and all justifications or underlying evidence required for a reader to understand and replicate the calculations.[10]

Step 6. Request Regulatory Approval

If the evaluation in Step 5 results in a proposal that is less costly than the best alternative utility reliability procurement and is cost-effective, reliable, prudent, and environmentally responsible, then Rhode Island Energy will file for regulatory approval of the system reliability procurement solution.

Figure 10 provides examples of which regulatory avenues Rhode Island Energy may pursue for approval for various solutions, where the wires or pipes solution (yellow row) represents the best alternative utility reliability procurement solution and subsequent rows (gray) represent system reliability procurement. Please note that Figure 10 is not intended to be comprehensive or deterministic; Rhode Island Energy will consider all appropriate regulatory avenues for each system reliability procurement solution.

Figure 10. Examples of filings through which regulatory approval may be requested for an incomplete set of potential solutions to system needs or optimization

Solution Description	Regulatory Filing	Timing of Filing
Wires or Pipes Solution	Electric or Gas Infrastructure, Safety, and Reliability ("ISR") Plan	Annual filing each December
Third-Party Solution (Technology Agnostic)	SRP Investment Proposal	December, alongside ISR Plan
Utility-Administered Energy Efficiency	SRP Investment Proposal	December, alongside ISR Plan
Utility-Administered Demand Response	SRP Investment Proposal	December, alongside ISR Plan
Utility Owned and Operated Energy Storage	Electric ISR Plan	Annual filing each December
Renewable Energy Incentives	Renewable Energy Growth Program (zonal incentive)	Annual filing each November

Step 7. Implement Solution

Pending regulatory approval, Rhode Island Energy will proceed expeditiously with the system reliability procurement solution. Any third-party solution will require an executed contract between the third party and Rhode Island Energy.

Contracts for third-party system reliability procurement solutions may include terms and conditions covering performance expectations, penalties for non-performance, and data sharing and transparency. An example of such language is below for reference:

[10] Subject to protection of confidential data and sources.

> *"[Vendor] acknowledges that the Rhode Island System Reliability Procurement Program ("Program") is funded by Rhode Island customers through the energy efficiency surcharge on their bills [or other rate mechanism]. [Vendor] agrees to cooperate with Rhode Island Energy ("RIE") and provide any documentation and/or data related to the Program in its possession to RIE for purposes of ensuring that RIE can (i) comply with any directives issued by the Rhode Island Public Utilities Commission ("PUC") or other authorized governmental agency and (ii) respond to any data requests made by the PUC or other governmental agency. [Vendor] also agrees that such documentation and/or data as well as this Agreement may be publicly filed by RIE in regulatory proceedings related to the Program. [Vendor] further agrees to comply with all requirements as reasonably deemed necessary by RIE to ensure that [Vendor] is qualified to serve as a vendor within the Program."*

Reporting and Continuous Improvement
Rhode Island Energy is committed to robust procurement and evaluation of system reliability procurement solutions.

To promote transparency, Rhode Island Energy will report results of all procurements, including assessments of the viability of utility-administered solutions. Such reporting will be included within *System Reliability Procurement Annual Reports*. For more information, see Section 7 of this *2024-2026 SRP Three-Year Plan*.

In the spirit of continuous improvement, Rhode Island Energy always encourages and accepts feedback from third-party solution providers, including both bidders and non-bidders. To provide feedback, please email Carrie Gill, Head of Electric Regulatory Strategy: cagill@rienergy.com.

Section 3. Electric System Needs and Optimization

Reducing Supply Costs through Electric Demand Response

System Need or Optimization

Electricity supply costs are partially driven by the high cost of electricity during the few hours of the year when we use the most electricity. During these "peak periods," the most expensive generators are needed to supply enough electricity to meet demand, and their cost is factored into the supply rates customers incur.

Although Rhode Island Energy is an electricity delivery company (akin to FedEx or UPS for delivering packages), we are obliged to help customers who choose not to buy supply from a third-party supplier by buying electricity in bulk on the wholesale market. Rhode Island Energy cares about helping customers access the most affordable electricity and, as such, has identified an opportunity to reduce supply costs by incentivizing demand reductions during peak periods.

System Reliability Procurement – Electric System Screening Criteria

This optimization meets all four electric system screening criteria and is, therefore, an opportunity for system reliability procurement:

1. The optimization is not related to an asset condition issue;

2. The optimization is eligible because the optimization requires load relief;

3. The opportunity for system reliability procurement is likely to garner sufficient market interest; and

4. There is adequate time to implement a system reliability procurement solution.

Best Alternative Utility Reliability Procurement Solution

Demand response proposed for this system need is specifically to reduce system-level peak demand. There is no best alternative utility reliability procurement solution at this time.[11,12]

Solicit and Evaluate System Reliability Procurement Proposals

This system reliability procurement opportunity has been addressed since 2019 through the Company's demand response program, branded ConnectedSolutions.[13] As of July 2023, approximately 8,000 customers are participating in ConnectedSolutions through their connected thermostats, battery energy storage systems, and production process curtailments. In aggregate, the participation of these customers has led to a meaningful reduction in peak load resulting in $74 million in costs avoided for our customers. To leverage the value of program continuity, Rhode Island Energy proposes to maintain ConnectedSolutions through 2026.[14]

To administer ConnectedSolutions, Rhode Island Energy partners with a number of curtailment service providers, contracts with a residential demand response vendor, and collaborates with

[11] Rhode Island General Laws 39-1-27.7.b(1)(iii) establishes "demand response, including, but not limited to, distributed generation, back-up generation, and on-demand usage reduction, that 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" as an eligible activity within system reliability procurement.

[12] The current demand response program is not capable of managing loads in response to circuit peaks because the current demand response program does not have the necessary inputs, including localized data, to sufficiently manage the distribution system with the existing software/systems. Rhode Island Energy's Grid Modernization Plan analysis identified a need to dispatch demand response resources with an understanding of both localized resource characteristics and system topology. The current system is incapable of doing this for two reasons. First, the current electric system does not have the requisite equipment (sensors, meters, etc.) to provide the data required to understand system topology. Second, the current demand response management system does not have the functionality to pair these two attributes (resource characteristics and system topology). The proposed grid modernization investments include the requisite equipment to provide the data required to understand the system topology and associated limitations on a granular basis. This understanding will provide incremental benefits, such as having the ability to provide localized solutions to address system needs, which will increase the impact of the existing demand response programs. Rhode Island Energy recognizes circuit-focused peak load management is an important functionality for achieving the State's climate and clean energy mandates safely, reliably, and affordably. Rhode Island Energy notes that its proposed grid modernization, our demand response program can be improved to (1) be tied not only to peak load reduction, but also to peak generation management; (2) be tied to distribution system constraints for better infrastructure avoidance; and (3) be integrated and scaled to levels commensurate with State policy drivers. Furthermore, Rhode Island Energy's proposed advanced metering functionality will (i) provide more granular and timely meter data; (ii) improve the Company's ability to dispatch resources; and (iii) allow for more accurate measurement and evaluation of performance. The granular data provided by these investments would be used with the grid modernization investments to provide system-wide real time visibility.

[13] ConnectedSolutions had previously been housed within filings related to energy efficiency (e.g., *2021-2023 Energy Efficiency Three-Year Plan*, *2023 Energy Efficiency Annual Plan*). Beginning in 2024, Rhode Island Energy will include ConnectedSolutions within filings related to system reliability procurement instead.

[14] Although this *2024-2026 SRP Three-Year Plan* only pertains to activities through 2026, Rhode Island Energy does envision the continuation of a demand response program past 2026, subject to future design modification and appropriate regulatory review.

major distribution utilities throughout the region to coordinate demand response events. Rhode Island Energy will continue to coordinate with and grow this ecosystem of third-parties, participants, and partner utilities to increase collective demand reduction and resulting benefits. In the last quarter of 2023, Rhode Island Energy will solicit proposals for a third-party vendor to work with us to achieve a certain level of peak reduction annually for the 2024-2026 period.

Request Regulatory Approval

Rhode Island Energy will request regulatory approval for ConnectedSolutions via a *System Reliability Procurement ("SRP") Investment Proposal* to be filed in December alongside, but separately from, the *Electric Infrastructure, Safety, and Reliability ("ISR") Plan*.[15] The *SRP Investment Proposal* will include program design specifications, budget, and anticipated participation and impacts. Additional discussion and details about the proposed trajectory of ConnectedSolutions is in Appendix 4.

Implement Solution

Pending regulatory approval, Rhode Island Energy will reopen ConnectedSolutions for the 2024 peak demand season, beginning in Spring 2024. Rhode Island Energy will report the resulting impacts in its *SRP Annual Report*.[16]

[15] As is recommended by the Least-Cost Procurement Standards (2023 version) Section 5.5.A.
[16] For more information on annual reporting, see Section 7.

Improving Reliability in Woonsocket

System Need or Optimization

In the Blackstone Valley South Area Study, Rhode Island Energy identifies a system need on a feeder in Woonsocket (excerpt below).[17]

Feeder 112W43 Reconductoring Options 1

Reliability can be improved by reconductoring ~5,340' of cross arm and armless to spacer cable along West Wrentham Road from pole #35 to pole #82. Refer to Appendix 7.6 for detailed plan development drawings. The wires solution should be further investigated. An infrared scan of the OH distribution equipment was completed in May 2021 and the issues have been resolved. Tree trimming was performed in FY20.

Spend	Cost ($M)
CapEx	$ 1.000
OpEx	$ 0.020
Removal	$ 0.080
Total	$ 1.100

Feeder 112W43 Non-wire Alternative Option 2

There is approximately 94% of total feeder connected kVA and 93% of total feeder customers past the reconductored section mentioned in Option 1. Based on the assessment of applicability of non-wires alternatives, the preferred solution may be a good candidate to go to market for an NWA solution. The NWA solution is currently being evaluated internally. Due to the ongoing NWA review, the wires solution cost identified above will not be included in the cost summary table below and in section 7.

Electric System Screening Criteria

This optimization meets all four electric system screening criteria and is, therefore, an opportunity for system reliability procurement:

1. The optimization is not related to an asset condition issue;
2. The optimization is eligible because the optimization requires load relief;
3. The opportunity for system reliability procurement is likely to garner sufficient market interest; and
4. There is adequate time to implement a system reliability procurement solution.

[17] See page 34, available here: https://systemdataportal.nationalgrid.com/RI/documents/Blackstone_Valley_South_Area_Study_Report_Rev1_final_signed_redacted.pdf

Best Alternative Utility Reliability Procurement Solution

As discussed in the Area Study, above, the best alternative utility reliability procurement solution involves reconductoring approximately one mile of cable. This solution is anticipated to cost $1.1 million.

Next Step: Solicit System Reliability Procurement Proposals

Rhode Island Energy plans to develop and issue an RFP for this system reliability procurement opportunity in 2024.

Section 4. Gas System Needs and Optimization

Gas Demand Response

System Need or Optimization
During the coldest days of the year when our system is near daily or hourly peak demand, upstream or on-system constraints may result in demand exceeding available pipeline capacity in certain areas on the system. Historically, Aquidneck Island has been a capacity constrained area that is closely evaluated by Rhode Island Energy with respect to gas procurement and system planning.

System Reliability Procurement – Gas System Screening Criteria
This system need is not related to an asset replacement investment. It qualifies as an eligible system need or optimization, is likely to garner sufficient market interest, and there is adequate time to implement a system reliability procurement solution. Therefore, this system need passes the gas system screening criteria and is a system reliability procurement opportunity.

Best Alternative Utility Reliability Procurement Solution
Gas demand response is a pilot program. We are trying to understand the scalability of the program and the degree to which it might offset a utility reliability procurement. Hence, it is not appropriate to evaluate the pilot program against a utility reliability procurement solution at this time.

Solicit System Reliability Procurement Proposals
For this system need, Rhode Island Energy administers a demand response pilot program for large, firm commercial and industrial customers, specifically those customers with gas equipment that can be curtailed without compromising safety.

The demand response pilot program incentivizes the deferral or avoidance of gas use during peak periods through adjusting thermostat settings or by temporarily switching to an alternative, back-up heating source. Testing the efficacy of gas demand response will allow Rhode Island Energy to understand gas demand response's impact on gas system needs and optimization, customer interest, effectiveness of incentive levels, and scalability of the program, as well as its potential applicability to other customer classes.

Because the gas demand response program is in the pilot stage and designed to test the benefits of reducing gas system peak demand, customer adoption of gas demand response, the incentive levels required drive participation, and RI Energy's role in influencing market adoption, it is, by nature of its design and goals, necessary for the Company to administer the program. Following the Gas DR Pilot, Rhode Island Energy will evaluate whether there is value in launching a full-scale demand response program.

Evaluate Possible Solutions

Gas demand response may have the potential for many system benefits and value streams, such as alleviating local distribution system constraints, increasing system flexibility, delaying infrastructure investments, and providing revenue to participants. The gas demand response pilot program will target 40-50 dekatherms ("Dth") of hourly peak demand reduction in the winter of 2023/2024. While gas demand response does not directly address climate change, greenhouse gas emissions may be reduced due to participation during peak demand events and may help avoid gas infrastructure investments.

Request Regulatory Approval

Rhode Island Energy will request regulatory approval for its gas demand response pilot program via a *System Reliability Procurement Investment Proposal* to be filed in November, separate from the *Gas Infrastructure, Safety, and Reliability ("ISR") Plan* to be filed in December. The *SRP Investment Proposal* will include program design specifications, budget, and anticipated participation and impacts. We discuss further details about the trajectory of the demand response program in Appendix 4.

Implement Solution

In its *SRP Investment Proposal*, Rhode Island Energy will propose the continuation of – and potential expansion to include residential and small-business customers with hybrid gas-electric heating systems – its gas demand response pilot program during peak gas demand season beginning in winter 2024. However, gas demand response hasn't provided the level of relief anticipated due to lack of performance during called events and low customer interest so enhancements are needed to create a more effective program. The learnings for the pilot program going forward will focus on how to increase program enrollment, participation during call events, and potential expansion of the program beyond large commercial and industrial customers. Aquidneck Island will continue to be a particular focus, but other areas with similar capacity constraints will be evaluated. Rhode Island Energy will report the resulting impacts of its demand response program in its SRP Annual Reports.[18]

[18] See Section 7 for more information about annual reporting.

Section 5. Market and Stakeholder Engagement

Engagement for Solicitations

In service to the objective of evaluating all possible solutions on a level playing field, Rhode Island Energy is interested in ensuring all competitive proposals are presented. To mitigate risk of an otherwise viable solution not being proposed due to lack of awareness about an RFP, Rhode Island Energy will conduct outreach for its system reliability procurement RFPs in the following ways:

1. Rhode Island Energy will post all RFPs for system reliability procurement publicly on the System Data Portal website.
2. Rhode Island Energy will email its list of third-party vendors when the RFP is issued and in reminder prior to the due date.
3. Rhode Island Energy will notify the System Reliability Procurement Technical Working Group so that members may conduct outreach to their constituents and colleagues.
4. Rhode Island Energy will notify the Energy Efficiency Technical Working Group so that members may conduct outreach to their constituents and colleagues.
5. Rhode Island Energy will make announcements at meetings of the Energy Efficiency and Resource Management Council and the Distributed Generation Board.

Rhode Island Energy welcomes ideas from potential bidders for other avenues of outreach that would be beneficial.

System Data Portal

Rhode Island Energy maintains an interactive website where third parties can access information about the electric distribution system, called the "System Data Portal." The primary objective of the System Data Portal is to use information to nudge development of distributed energy resources to locations on the grid that provide relatively more operational value. An ancillary benefit is that developers can gain insight into potential development locations that may result in relatively low interconnection costs and/or relatively quick interconnection times. Appendix 3 contains more information about how to use the System Data Portal, including specific use cases for various stakeholders including distributed generation developers, electric vehicle charging infrastructure developers, and building developers.

Rhode Island Energy is in the process of migrating the System Data Portal from National Grid's servers to PPL's servers, expected to be complete by May 2024. This migration will preserve all key components of the System Data Portal, including Company Reports, Distribution System Data Map, Heat Map, and Hosting Capacity Map, all of which will be updated by the end of the first quarter of each year on an ongoing basis.

Rhode Island Energy will make the following changes and improvements to the System Data Portal:

- Solicitations for System Reliability Procurement will be housed within the Company Reports tab instead of the tab currently titled "NWA." By housing all relevant materials together (i.e., solicitations, area studies, and the *2024-2026 SRP Three-Year Plan*), we hope third-party solution providers and potential bidders can more easily access pertinent information for beneficial development of distributed energy resources and successful proposals for non-wires solutions.

- Equivalent materials for the gas distribution system and solicitations for non-pipes solutions will be added to the Company Reports tab.
- Rhode Island Energy will remove the fleets layer from the heat map, but add a map showing loading hosting capacity. The original objective of this layer was to help third parties identify fleets that could potentially be electrified. However, there is no compelling evidence that the fleet layer is actively used and there are administrative challenges with updating the layer. Instead, we will add a full map tab showing loading hosting capacity on each feeder. This layer will provide third parties information about which feeders may have the capacity to accommodate electric vehicle charging infrastructure with relatively low interconnection cost.
- Rhode Island Energy will remove the tab "SLR," which shows projections of sea level rise using data sourced from the National Oceanic and Atmospheric Administration. To aid third parties in developing distributed energy resources in locations with lower climate risk, Rhode Island Energy will add layers to each map tab that allow users to toggle on/off map layers from Rhode Island's STORM TOOLS, a suite of maps that show coastal flooding for various levels of storm and sea level rise that is used by the Coastal Resources Management Council. Rhode Island Energy recognizes the importance of climate resilience and climate adaptation for our energy resources and welcomes suggestions for other useful map overlays on an ongoing basis.

System Reliability Procurement Technical Working Group

The SRP Technical Working Group (TWG) is an external stakeholder group convened and administered by Rhode Island Energy for the sole purpose of advising Rhode Island Energy on matters related to System Reliability Procurement, as defined by Least-Cost Procurement Statute under RIGL 39-1-27.7. The SRP TWG is not a statutory or regulatory requirement, nor is the group public. Members of the SRP TWG include the Rhode Island Division of Public Utilities and Carriers, Rhode Island Office of Energy Resources, Energy Efficiency and Resource Management Council, Acadia Center, Green Energy Consumers Alliance, Northeast Clean Energy Coalition, and Conservation Law Foundation.[19] Rhode Island Energy will continue to convene the SRP TWG throughout 2024-2026. Topics of discussion for this time period may include but are not limited to process improvements for system reliability procurement solicitations and evaluations, review of *SRP Investment Proposals* and *SRP Annual Reports*, improvements for the System Data Portal, and other topics to be identified. For more information about the SRP TWG, please email Carrie Gill at cagill@rienergy.com.

[19] While Commerce RI, Rhode Island Office of the Attorney General, and Rhode Island Infrastructure Bank have been members and are welcome to continue to participate, there are currently no representatives from these organizations who are active in the SRP TWG.

Section 6. Performance Incentive Plan

Rhode Island Energy proposes performance incentive structures for (i) demand response and (ii) implementation of a system reliability procurement solution. Both incentives are structured as shared savings, where the demand response performance incentive shares avoided supply costs and system reliability procurement shares avoided distribution costs.

Through system reliability procurement, Rhode Island Energy is creating value. The Company proposes to share this value between customers and shareholders, thereby accomplishing the Company's dual mission of delivering safe, affordable, reliable, sustainable energy to customers and long-term value to shareholders.

Please note that the incentive structures below are conceptual; Rhode Island Energy will propose specific performance incentives aligned with this structure in each of its SRP Investment Proposals.

<u>Demand Response Performance Incentive</u>

Rhode Island Energy proposes a dollar per megawatt peak reduction performance incentive for its demand response achievements.[20] The level of incremental incentive is tied to quantitative net benefits, as described below. The objective is to share quantifiable cash savings with customers.

Quantitative net benefits

- Electric Savings: Energy
- Electric Savings: Capacity
- Resource Benefits: Electric Energy
- Resource Benefits: Electric Energy DRIPE
- Resource Benefits: Electric Capacity
- Less: Program Costs

<u>System Reliability Procurement Performance Incentive</u>

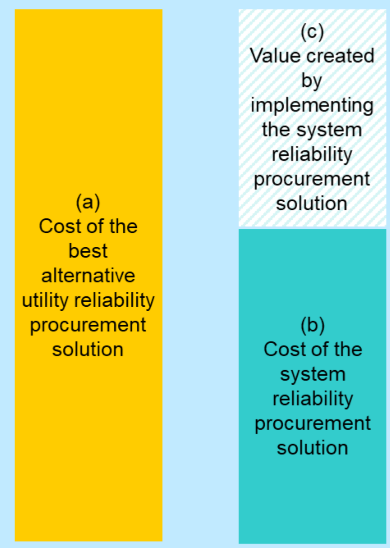
Rhode Island Energy proposes a shared savings mechanism for successfully implementing system reliability procurement solutions. Savings is defined as avoided costs between the system reliability procurement solution and the best alternative utility reliability procurement solution, where 80 percent is allocated to customers and 20 percent is earned by the Company on an annual basis.

Rhode Island Energy additionally proposes a minimum performance incentive for the successful implementation of each system reliability procurement solution, commensurate with the lost return its shareholders would have earned on the best alternative utility reliability procurement

[20] This proposal is similar to the System Efficiency Performance Incentive Mechanism developed and approved via Docket No. 4770, except that it is specific to system peak reduction achieved through demand response.

solution. This minimum ensures that there is no structural earnings incentive for one type of solution over another. Figure 10 illustrates the share value approach to a performance incentive.

Figure 10. System Reliability Procurement Performance Incentive



Performance incentive =
MAX {allowed return on best alternative utility reliability procurement solution, 80% * (c)}

When the Company files its proposed system reliability procurement solution, the filing will contain details of the best alternative reliability procurement solution, including annual financials, for full regulatory scrutiny. The same details will be provided for the proposed system reliability solution. The Company will request regulatory approval of the performance incentive, implying regulatory review and approval of the specific financials of the best alternative utility reliability procurement solution and the proposed system reliability procurement solution. The performance incentive will be calculated and included within each annual system reliability procurement report, using actual data of the prior year's expenses on the approved system reliability procurement solution relative to the best alternative utility reliability procurement solution. This performance incentive will be recovered via the same cost recovery mechanism used to fund the proposed system reliability procurement solution.

Section 7. Annual Reporting

Rhode Island Energy will submit an SRP Annual Report to the Rhode Island Public Utilities Commission by June 1 of each year covering activities completed within the prior calendar year (e.g., the 2024 SRP Annual Report will cover activities conducted January 1 through December 31, 2024, and will be submitted by June 1, 2025). With the dual objectives of transparently reporting activities to interested stakeholders and holding the Company accountable, each annual report will include the following information:

- Results of each step included in the SRP process described in Section 2;
  - Where results of screening for electric and gas system reliability procurement opportunities, with any opportunities added to a comprehensive listing of opportunities with summary information about system needs or optimization and next step/date of next step (akin to the descriptions provided in Sections 3 and 4);
  - Results of Steps 4-5 (solicitation and evaluation) include proposals and their evaluation outcomes for internally-sources system reliability procurement solutions that did or did not advance to Step 6 (regulatory review);
  - Calculation of performance incentives, as applicable, resulting from successful implementation of system reliability procurement (Step 7)
- A summary of any major changes to the System Data Portal (beyond routine updating of data);
- A summary of engagement with the SRP Technical Working Group; and
- A description of any proposed changes to process, funding, performance incentive, annual reporting, or any other system reliability procurement activity with a justification for the proposed change and any request regulatory ruling related to the proposed change.

Section 8. Consistency with Least-Cost Procurement Standards

In this section, Rhode Island Energy discusses how the 2024-2026 SRP Three Year Plan – specifically the proposed system reliability procurement process – is consistent with the requirements of Least-Cost Procurement Standards Section 1.3. Key excerpts are copied below for easy and direct reference.

Rhode Island Energy will include detailed discussion and documentation (where appropriate) specific to each System Reliability Procurement Investment Proposal to evince its adherence to Least-Cost Procurement Standards Section 1.3.

<u>Least-Cost Procurement Standards Section 1.3.A</u>
"Least-Cost Procurement shall be cost-effective, reliable, prudent, and environmentally responsible. ... System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement."

The evaluation step of the system reliability procurement process described in Section 2 Step 5 of this Plan is consistent with Standards Section 1.3.A because the evaluation criteria are structured such that any proposed system reliability procurement solution that is not cost-effective, reliable, prudent, environmentally responsible, and lower than the cost of the best alternative utility reliability procurement solution is removed from further consideration. The proposed system reliability procurement process and evaluation criteria guarantee consistency with Standards Section 1.3.A.

<u>Least-Cost Procurement Standards Section 1.3.B</u>
"When preparing any cost test or resource assessment, including the RI Test, the following principles will be applied: i. Supply-side and demand-side alternative energy resources shall be compared in a consistent and comprehensive manner. ii. Cost tests shall be created using the RI Framework and account for applicable policy goals, as articulated in legislation, PUC orders, regulations, guidelines, and other policy directives. iii. Cost tests shall account for all relevant, important impacts, even those that are difficult to quantify and monetize. Where applicable cost or benefit categories cannot be quantified, such categories shall be qualitatively assessed.[21] iv. Cost tests shall be symmetrical, for example, by including both costs and benefits for each relevant type of impact. v. Analyses of the impacts of investments shall be forward-looking, capturing the difference between costs and benefits that would occur over the life of the investments with those that would occur absent the investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis. vi. Cost tests shall be completely transparent and should fully document and reveal all relevant inputs, assumptions, methodologies, and results."

The system reliability procurement process described within Section 2 of this Plan includes a step for evaluating system reliability procurement proposals. Within this step, Rhode Island

[21] "Qualitative assessments may include relative descriptions of magnitude and direction."

Energy describes its adherence to the principles put forth in Standards Section 1.3.B. In this manner, the Plan is consistent with this requirement of the Standards.

<u>Least-Cost Procurement Standards Sections 1.3.C-F</u>
These sections stipulate criteria that shall or may be used in the assessment of the extent to which system reliability procurement solutions are cost-effective, reliable, prudent, and environmentally responsible.

The stipulations for determining cost-effectiveness are built into the system reliability procurement process in evaluation of system reliability procurement project proposals. Rhode Island Energy describes its adherence to the Least-Cost Procurement Standards in Section 2 Step 5.

<u>Least-Cost Procurement Standards Sections 1.3.H</u>
"Lower than the cost of the best alternative Utility Reliability Procurement i. The distribution company shall compare the cost of System Reliability Procurement measures, programs, and/or portfolios to the cost of the best alternative Utility Reliability Procurement option using all applicable costs enumerated in the RI Framework. The distribution company shall provide specific costs included in the Cost of System Reliability Procurement. ii. At a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test. iii. The distribution company shall describe which costs in the RI Framework were included in the cost of System Reliability Procurement and which costs are included in the alternative Utility Reliability Procurement. For any categories that are not included in either, the distribution company shall describe why these categories are not included."

Rhode Island Energy explicitly commits to adhere to Least-Cost Procurement Section 1.3.H in its assessment of the cost of the system reliability procurement solution relative to the best alternative utility reliability procurement solution.[22]

[22] Least-Cost Procurement Section 1.3.H is the relevant section for System Reliability Procurement; Section 1.3.G is relevant for Energy Efficiency and, as such, is not included for discussion herein.

Section 9. Request for Ruling

In accordance with Least-Cost Procurement Standards (2023) Chapter 4.5 (Docket No. 23-07-EE), Rhode Island Energy respectfully requests that the Commission

A. approve screening requirements and implementation plans described in Sections 2-5;
B. approve annual reporting requirements described in Section 7; and
C. approve the performance incentive plan described in Section 6.

Please note that Rhode Island Energy is not requesting any ruling on the draft System Reliability Procurement Investment Proposals contained in Appendix 4 at this time; final versions of these proposals will be filed with the Commission for review and approval separately.

Appendices

Appendix 1. Slide Deck Format of *2024-2026 SRP Three-Year Plan*

See attachment.

2024-2026
System Reliability Procurement
Three-Year Plan

Rhode Island Energy™
a PPL company

Front Matter

2024-2026
System Reliability Procurement (SRP)
Three-Year Plan

For action by the Rhode Island Energy Efficiency and Resource Management Council on October 19, 2023

To be filed on/by November 21, 2023, with:

Rhode Island Public Utilities Commission in RIPUC Docket No. 23-XX-EE

Prepared by:
The Narragansett Electric Company d/b/a Rhode Island Energy

Rhode Island Energy™
a PPL company

Executive Summary

Executive Summary

System Reliability Procurement (SRP) encompasses the activities conducted by The Narragansett Electric Company d/b/a Rhode Island Energy to meet or mitigate a gas or electric system need or optimization that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[1] In this *2024-2026 SRP Three-Year Plan* (“Plan”), Rhode Island Energy summarizes its proposed implementation plan for system reliability procurement. This Executive Summary is intended to provide a high-level overview.

How does Rhode Island Energy identify opportunities for system reliability procurement?
Rhode Island Energy’s system planners identify opportunities for system reliability procurement as they identify and screen system needs. The figure to the right describes the entire system reliability procurement process from identifying system needs to implementing system reliability procurement solutions. Section 2 describes this process in detail, and Sections 3 and 4 identify opportunities for system reliability procurement solutions in the queue.

[1] Per the Rhode Island Public Utilities Commission’s Least-Cost Procurement Standards, 2023 version.

Figure ES-1. Overview of System Reliability Procurement Process

Identify system needs	Engineers use forecasts about energy demand and distributed energy resources alongside information like asset age to model the electric and gas systems. These models help engineers pinpoint system needs that should be resolved soon.
Screen for possible solutions	Engineers apply screening criteria to understand which types of solutions are potentially feasible. Possible solutions include infrastructure investment, utility-run programs, and system reliability procurement.
Scope best alternative URP solution	Engineers scope the best alternative utility reliability procurement (URP) solution for the system need or optimization. Possible solutions are utility owned and operated by definition.
Solicit proposals	If system reliability procurement is a potential feasible solution, then engineers will work with the procurement team to develop a competitive bid process for third-party vendors to propose their solutions.
Evaluate proposals	Representatives from throughout Rhode Island Energy will help evaluate proposals from third-party vendors using pre-defined evaluation criteria that assess technical and economic viability.
Request regulatory approval	If a proposal is successful, then Rhode Island Energy will formally submit the solution for regulatory approval through an “SRP Investment Proposal.”
Implement solution	If the SRP Investment Proposal is approved, Rhode Island Energy will work with the third-party vendor to implement the solution in time to resolve the system need.

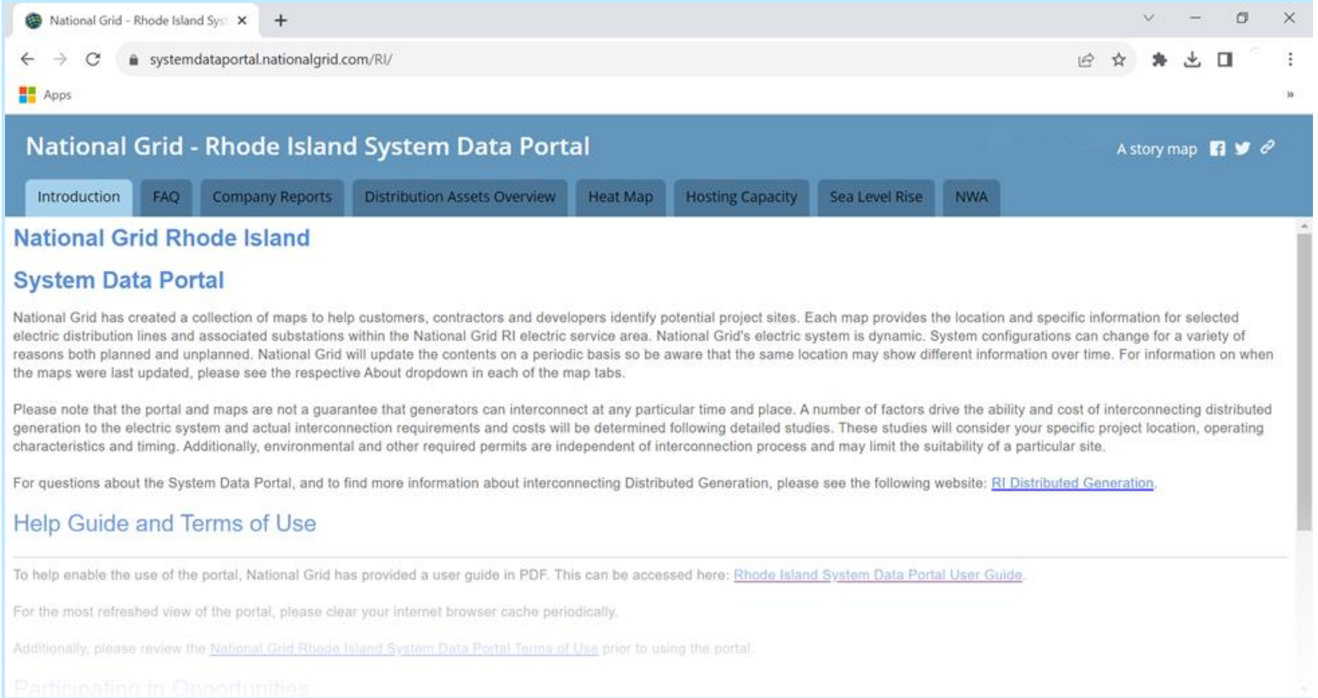
Executive Summary

Rhode Island Energy™
a PPL company

<u>How can third-party solution providers find opportunities to propose solutions?</u>

Third-party solution providers can find opportunities for system reliability procurement via Rhode Island Energy’s System Data Portal, available here: https://systemdataportal.nationalgrid.com/RI/.[2] Specifically, third-party solution providers can access open solicitations for system reliability procurement solutions using the NWA tab and can follow along with Rhode Island Energy’s system planning by viewing the area studies; system reliability procurement plans; and infrastructure, safety, and reliability plans in the Company Reports tab. Section 5 includes additional discussion of planned updates and improvements to the System Data Portal. Appendix 5 contains a helpful user guide to assist users in getting the most out of the System Data Portal.

Figure ES-2. System Data Portal



[2] Please note that Rhode Island Energy is in the process of transitioning the System Data Portal from prior parent company National Grid; users should expect branding and company identification to transition during 2023-2024.

Executive Summary

Rhode Island Energy™
a PPL company

<u>How can stakeholders engage?</u>
In the spirit of transparency and continuous improvement, Rhode Island Energy welcomes stakeholder engagement through the following channels:

- ✓ Third-party solution providers can add their contact information to Rhode Island Energy's distribution lists for solicitations; these distribution lists may also be used for other communications to solicit feedback from third parties on system reliability procurement processes (email cagill@rienergy.com to be added to distribution lists).

- ✓ Stakeholders representing customer, third party, or other interests can engage directly with Rhode Island Energy (email cagill@rienergy.com to discuss the most productive way to engage).

- ✓ Anyone (third-party solution providers, stakeholder groups, customers, etc.) can follow along with and engage via the Rhode Island Energy Efficiency and Resource Management Council (EERMC); visit the EERMC's website to learn more about the EERMC's oversight role in system reliability procurement and identify meetings to attend and ways to engage: www.rieermc.ri.gov.

- ✓ Anyone (third-party solution providers, stakeholder groups, customers, etc.) can follow along with and engage as appropriate in regulatory proceedings; visit the Rhode Island Public Utilities Commission's website to access dockets related to system reliability procurement: www.ripuc.ri.gov.

- ✓ Just have a general question or thought? Email Carrie Gill at cagill@rienergy.com to discuss.

Executive Summary

How is SRP coordinated across other distribution system planning and investment activities?
Rhode Island Energy conducts a number of business activities in the pursuit of delivering safe, affordable, reliable, and sustainable energy to our customers. As such, teams throughout Rhode Island Energy coordinate to make sure all investments and customer programs are aligned to make the most effective impacts. The table below provides some detail about how Rhode Island Energy coordinates between system reliability procurement and other distribution system planning and investment activities.

Infrastructure, Safety, and Reliability Planning	All distribution system planning, whether it results in utility reliability procurement that proceeds through *Infrastructure, Safety, and Reliability Plans* or system reliability procurement, begins with identifying system needs using forecasts about energy demand and distributed energy resources alongside information like asset age to model the electric and gas systems. Coordination between utility reliability procurement and system reliability procurement is inherent to Rhode Island Energy's internal structure of identifying system needs and ensures no duplication of efforts.
Energy Efficiency	System reliability procurement and energy efficiency are both authorized through Rhode Island's Least-Cost Procurement Statute and further stipulated through regulatory standards. Rhode Island Energy's energy efficiency team will propose the viability of targeted energy efficiency in response to open solicitations for system reliability procurement, to be evaluated alongside proposals third-party solution providers. In particular, demand response programs (conducted as system reliability procurement) overlay performance incentives on purchase and financing incentives accessed through energy efficiency programs. Staff are fully coordinated on leveraging both incentive streams to maximize demand response program impacts.
Customer Communications	Rhode Island Energy's customer communications team is fully integrated into outreach and engagement for system reliability procurement during the 2024-2026 period. Outreach and engagement could include open solicitations for system reliability procurement, awareness of the System Data Portal, education and volunteer peak demand reduction for ConnectedSolutions, and other information related to system reliability procurement activities, as appropriate.
Grid Modernization and Advanced Metering	Rhode Island Energy has filed proposals with the Rhode Island Public Utilities Commission to transition to advanced metering (Docket No. 22-49-EL) and modernize the electric grid (Docket No. 22-56-EL), both of which are ongoing proceedings as of September 1, 2023. Regardless of the outcomes of either proceeding, system reliability procurement will continue and Rhode Island Energy will continue to screen system needs for the possibility of having system reliability procurement solutions, for which Rhode Island Energy would solicit proposals. Indeed, enhanced visibility, communications, and control achieved through advanced metering and grid modernization would benefit Rhode Island Energy's ability to forecast system needs and employ system reliability procurement solutions.
Last Resort Service Supply Procurement	Through a RI PUC approved procurement process, Rhode Island Energy procures energy supply on behalf of all customers who have chosen not to receive supply from an alternate supplier (i.e. retail or competitive supplier). Rhode Island Energy's procurement team is involved in informing decisions about the scale of peak reduction targeted through demand response activities within system reliability procurement.

Executive Summary

For more information…
The following *2024-2026 SRP Three-Year Plan* describes Rhode Island Energy's vision for system reliability procurement throughout 2024-2026. Interested stakeholders, third-party solution providers, and energy system enthusiasts are encouraged to read on to learn more about Rhode Island Energy's system reliability procurement processes, upcoming activities and programs, regulatory compliance, and additional technical and conceptual details.

Section 1. Introduction

Introduction

System Reliability Procurement (SRP) encompasses the activities conducted by The Narragansett Electric Company d/b/a Rhode Island Energy to meet or mitigate a gas or electric system need or optimization by employing diverse energy resources, distributed generation, or demand response.[2] In this *2024-2026 SRP Three-Year Plan (“Plan”)*, Rhode Island Energy summarizes its proposed implementation plan for system reliability procurement.

The Rhode Island Public Utilities Commission provides principles for the design of each Three-Year Plan in their Least-Cost Procurement Standards, shown in Figure 1.

In designing this Plan, Rhode Island Energy translated the principles in Figure 1 to a set of four objectives and strategized how to build these objectives into the Plan. Figure 2, next page, connects principles A through C from Figure 1 to these objectives and actions. This figure was discussed with the SRP Technical Working Group on May 17, 2023, and the Energy Efficiency and Resource Management Council on May 18, 2023.[3]

Throughout this Plan, we include several figures and tables to aid in understanding and clarity. Figures with a blue background apply generally to the electric and gas systems. Figures with a yellow background provide definitions or other regulatory, statutory, or policy citations. Figures with a teal background are specific to the electric system. Figures with a purple background are specific to the gas system. The objective of this color coding is to assist readers in navigating this Plan.

Figure 1: General Plan Design and Principles

A. In order to meet Rhode Island’s gas and electric energy system needs and policy goals in a manner consistent with R.I. Gen. Laws §39-1-27.7, Three-Year SRP Plans should include both a broad consideration of needs and goals and broad consideration of solutions to these needs and goals in order to encourage optimal investment by the distribution company.

B. The Three-Year SRP Plan should be integrated with the distribution company’s distribution planning process and be designed, where possible, to complement the objectives of Rhode Island’s energy policies and programs as described in Section 3.2.A.

C. The Three-Year SRP Plan should be designed so that potential non-utility solution providers can understand how and when the distribution company makes decisions to implement System Reliability Procurement in lieu of Utility Reliability Procurement.

Source: Least-Cost Procurement Standards, Section 4.3 (Docket No. 23-07-EE)

[2] Rhode Island Public Utilities Commission’s Least-Cost Procurement Standards (Docket 23-07-EE).
[3] For more information about the SRP Technical Working Group, see Section 5. To date, the 2024-2026 SRP Three-Year Plan was discussed with the SRP TWG on May 17 and July 19, and with the Energy Efficiency and Resource Management Council on May 18.

Introduction

Rhode Island Energy™
a PPL company

Figure 2. RIE Priorities for the 2024-2026 SRP Three-Year Plan

A	B	C	Objectives	How
		√	**Readable**: Easy to navigate and understand by any reader, including third-party solution providers	• Restructuring sections and content to be more responsive to the LCP Standards Chapter 4 • Organizational discipline • Concise writing, figures
√	√		**Useful**: Demonstrate clear alignment and integration with other business functions and investment proposals	• Links to overarching business objectives • Cross references • Calling out contingencies if/when they exist
√		√	**Actionable**: Where we identify areas of innovation or improvement, provide clear and actionable workplans	• Work/research/discussions needed • Milestones • Interim and end deliverables • Eval process for internal EE/DR/etc efforts
√	√	√	**Compelling**: Clear proposals for PUC ruling with well-supported justification and reasoning	• Screening requirements and implementation plans for non-wires and non-pipes solutions • Annual reporting requirements • Performance metrics and incentive plan • Other proposals, as appropriate

Notes: Presented to and discussed with the SRP TWG on May 17, 2023, and with the Energy Efficiency and Resource Management Council on May 18, 2023. Columns A, B, and C correspond to principles A, B, and C in Figure 1. Teal coloring indicates the objectives advance those principles.

Contents

This Plan is organized into sections aligned with required content as described in Chapter 4.4 of the Least-Cost Procurement Standards. Non-wires solutions and non-pipes solutions are each addressed throughout each of the sections of this Plan. The appendices to this Plan provide additional details to aid in understanding of the Report and to comply with legal and regulatory reporting requirements.

Section 2. System Reliability Procurement Process

Overview

In this Section, Rhode Island Energy describes the system planning process, from identification of system needs, screening for system reliability procurement, and procuring, evaluating, and implementing solutions.

We describe each step in detail. Although many steps are the same regardless of whether the system need or optimization is for the electric or gas system, there are some steps in which we handle electric system needs differently from gas system needs. We take care in pointing out these differences and explain why these differences are appropriate within our pre-filed testimony.

Figure 3 summarizes the system reliability procurement process as a sequence of high-level steps. These high-level steps are fully integrated into the overall electric and gas system planning processes. We walk through each of these steps in order in the following subsections, and discuss report-outs on the results of each step within Section 7: Annual Reporting.

Figure 3. Overview of System Reliability Procurement Process

Identify system needs	Engineers use forecasts about energy demand and distributed energy resources alongside information like asset age to model the electric and gas systems. These models help engineers pinpoint system needs that should be resolved soon.
Screen for possible solutions	Engineers apply screening criteria to understand which types of solutions are potentially feasible. Possible solutions include infrastructure investment, utility-run programs, and system reliability procurement.
Scope best alternative URP solution	Engineers scope the best alternative utility reliability procurement (URP) solution for the system need or optimization. Possible solutions are utility owned and operated by definition.
Solicit proposals	If system reliability procurement is a potential feasible solution, then engineers will work with the procurement team to develop a competitive bid process for third-party vendors to propose their solutions.
Evaluate proposals	Representatives from throughout Rhode Island Energy will help evaluate proposals from third-party vendors using pre-defined evaluation criteria that assess technical and economic viability.
Request regulatory approval	If a proposal is successful, then Rhode Island Energy will formally submit the solution for regulatory approval through an “SRP Investment Proposal.”
Implement solution	If the SRP Investment Proposal is approved, Rhode Island Energy will work with the third-party vendor to implement the solution in time to resolve the system need.

Step 1. Identify System Needs and Optimization

The Rhode Island Energy team identifies system needs and opportunities to optimize system performance through routine distribution system planning studies, through annual distribution system planning processes, and through annual consideration of supply-related needs and opportunities.

Electric System
Engineers use electrical models to simulate conditions on the electric system, given inputs like forecasted load growth, forecasted penetration of distributed energy resources, and characteristics of electric assets, like age. These models help engineers pinpoint system issues and when they need to be addressed. Engineers do this type of planning every several years for geographical electrical areas (called area studies) and annually for targeted immediate system needs.

Engineers and supply procurement team members will also discuss potential supply constraints or needs on an annual basis. Rhode Island and the region typically experience peak supply demand on hot summer evenings, which can result in higher supply costs for customers. The team considers high supply costs as an opportunity for optimization of system performance.

Gas System
The process of identifying gas system needs and opportunities to optimize performance is very similar to that followed for electric system planning. Engineers use gas supply and distribution system models to perform a detailed analysis of facilities and system performance within identified geographic gas areas as well as for targeted immediate system needs. Gas engineers and the gas procurement team discuss potential supply constraints and needs as part of the system assessment. This process prioritizes the identification of capacity-constrained areas – i.e., locations on the gas system where forecasted peak demand exceeds the amount of pipeline capacity we can rely on to be available on the coldest winter days.

Figure 4. Definitions

Electric System Needs
Needs to serve both customer load and customer generation, including, but not limited to, system capacity (normal and emergency), voltage performance, reliability performance, protection coordination, fault current management, reactive power compensation, asset condition assessment, distributed generation constraints, operational considerations, and customer requests.

Gas System Needs
Needs to serve customers, including, but not limited to, system capacity (normal and emergency), pressure management, asset condition assessment, gas service that supports electric distributed generation, and operational considerations.

Optimization of System Performance
Improvement of the performance and efficiency of the gas or electric system that includes enhanced reliability, peak load reduction, improved utilization of both utility and non-utility assets, optimization of operations, and reduced system losses.

Source: Least-Cost Procurement Standards (2023 version)

Step 2. Screen for Possible Solutions

Rhode Island Energy™
a PPL company

Once a system need or opportunity for system optimization is identified, the Rhode Island Energy team screens for the possibility that a system reliability procurement solution may be technically and economically viable.

Figure 5 defines the two categories of possible solutions to a system need or optimization: system reliability procurement solutions with utility reliability procurement solutions.

Figure 5. Definitions

Utility Reliability Procurement
Procurement to meet or mitigate a gas or electric distribution system need or optimization that is not System Reliability Procurement and thus represents a utility-only investment or expenditure.*

* For example, many such Utility Reliability Procurement investments and operations are proposed in annual Infrastructure, Safety, and Reliability Plans filed pursuant to R.I. Gen. Laws § 39-1-27.7.1(c)(2).

System Reliability Procurement
Procurement to meet or mitigate a gas or electric distribution system need or optimization from a party other than the gas or electric utility** that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.***

** A utility proposal to own and operate non-traditional investment or new operations and maintenance services, such as new voltage-regulation equipment, battery storage, or vegetation management, and any vendor services associated with such investment or service, shall not be considered System Reliability Procurement per this definition. Such investments and services are, however, still subject to the Guidance Document issued in Docket No. 4600A.

*** Including, but not limited to, the resources named in R.I. Gen. Laws § 39-1-27.7(a)(1)(i)-(iii).

Source: Least-Cost Procurement Standards (2023 version)

Step 2. Screen for Possible Solutions

Rhode Island Energy™
a PPL company

Figure 6 compares and contrasts key terminology that describes various possible solutions to assist with understanding.

System reliability procurement encompasses solutions proposed by third-party vendors and solutions operated by Rhode Island Energy. However, utility reliability procurement is limited to solutions owned and operated by Rhode Island Energy.

System reliability procurement only encompasses non-wires and non-pipes solutions. Utility reliability procurement can encompass both wires/pipes solutions and non-wires/non-pipes solutions. Note that this step is technology agnostic; screening criteria for the possibility of a system reliability procurement solution to a system need or optimization are silent on technology alternatives.

Figure 6. Examples of Solutions and Relevant Terminology

	Wires/Pipes Solutions	**Non-Wires/ Non-Pipes Solutions**
Utility Reliability Procurement (URP)	Reconductoring Upsize transformers Pipe replacement	Utility-owned and operated battery storage CVR/VVO
System Reliability Procurement (SRP)	Not applicable	***Utility-run*** or ***third-party*** demand response or targeted energy efficiency ***Third-party*** owned and operated battery storage

Step 2. Screen for Possible Solutions – Electric System

Rhode Island Energy™
a PPL company

Engineers screen system needs for the potential viability of a system reliability procurement solution. This screening is fully integrated into the planning process and is part of the normal course of business.

Screening criteria are described in Figure 7. These screening criteria are applied by the engineering team to all electric system needs and opportunities for optimizing system performance that arise during Step 1.

System needs that fail any of the screening criteria will be proposed as "wires solutions" through Rhode Island Energy's annual Electric Infrastructure, Safety, and Reliability ("ISR") Plan at the appropriate time.

System needs that pass the screening then advance through the following steps to solicit and evaluate the viability of system reliability procurement solutions.

Figure 7. Screening Criteria for Non-Wires Solutions through System Reliability Procurement

Not an asset condition issue

Electric assets that have reached the end of their lifetimes need to be replaced; a non-wires solution (whether system reliability or utility reliability procurement) cannot resolve an asset condition issue.

Eligible system need or optimization

Eligible system needs and optimization include load relief, reliability, and supply cost mitigation. If the system need is load relief, the amount of load should not exceed 20% of total load in the area of the defined need.

Sufficient Market Interest

The system need or optimization must be substantial enough to plausibly result in market interest. Rhode Island Energy uses a guideline of the wires solution costing at least $1 million as a proxy for whether a system need is likely to gain sufficient market interest.

Adequate time to implement

There must be at least 24 months before the start date of non-wires solution implementation to allow adequate time to go to market, evaluate proposals, gain necessary approvals, and construct or deploy the proposed non-wires solution.

Additionally, by the Company's discretion, Rhode Island Energy may pursue a project that does not pass one or more of these screening criteria if there is reason to believe that a viable non-wires solution exists, assuming the benefits of doing so justify the costs.

Step 2. Screen for Possible Solutions – Gas System

Rhode Island Energy™
a PPL company

Gas system reliability procurement is a nascent program and process, requiring ongoing development so that full integration into the gas planning process and normal course of business can be achieved. As with the electric system, the objective is for gas engineers to screen system needs for the potential viability of a system reliability procurement solution. Given the emergent nature of the program, we anticipate the screening process and criteria may evolve, informed by experience and learnings. Any proposed changes will be submitted for regulatory approval per LCP Standards at the appropriate time.

Once embedded in the gas planning process, screening criteria will be applied by the engineering team to system needs and opportunities for optimizing system performance that arise during Step 1. Screening criteria for the gas system are described in Figure 8.

System needs that fail any of the screening criteria will be proposed as “pipes solutions” through Rhode Island Energy’s annual Gas Infrastructure, Safety, and Reliability (“ISR”) Plan at the appropriate time.

System needs that pass the screening then advance through the following steps to solicit and evaluate the viability of system reliability procurement solutions. Projects that meet the screening criteria will be prioritized in consideration of capacity-constrained areas on the gas system.

Figure 8. Screening Criteria for Non-Pipes Solutions through System Reliability Procurement

Not an asset replacement investment

Gas assets that pose immediate, local, and system-wide safety and/or reliability impacts must be replaced; a non-pipes solution (whether system reliability or utility reliability procurement) cannot resolve a critical safety or reliability issue.

Eligible system need or optimization

Eligible system needs and optimization include load reduction, load removal, and supply constraint mitigation.

Sufficient Market Interest

The system need or optimization must be substantial enough to plausibly result in market interest. Rhode Island Energy uses a guideline of the pipes solution costing at least $0.5 million as a proxy for whether a system need is likely to gain sufficient market interest.

Adequate time to implement

There must be at least 24 months before the start date of non-pipes solution implementation to allow adequate time to go to market, evaluate proposals, gain necessary approvals, and construct or deploy the proposed non-pipes solution.

Additionally, by the Company’s discretion, Rhode Island Energy may pursue a project that does not pass one or more of these screening criteria if there is reason to believe that a viable non-pipes solution exists, assuming the benefits of doing so justify the costs.

Step 3. Scope the Best Alternative URP

Least-Cost Procurement Standards require "System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement" (Section 1.3.A). Therefore, we first must understand what the best alternative utility reliability procurement solution is.

System engineers always develop their recommendation for the best utility reliability procurement solution. These solutions are described in area studies and annual Infrastructure, Safety, and Reliability ("ISR") Plans.

For any system need or optimization that passes the screening criteria in Step 2 of the system reliability procurement process, the cost of the best alternative utility reliability procurement solution will be denoted as the cost against which to compare system reliability procurement proposals.

Step 4. Solicit Proposals

Rhode Island Energy will solicit proposals for all possible solutions identified, whether from a third-party vendor or an internal business functional team (i.e., utility-run non-wires/non-pipes solutions). Solicitation will occur via a competitive Request for Proposals ("RFP"). Internally, a procurement specialist will work with engineers and others to develop the RFP, which will fully detail the scope of the system need or opportunity for optimization. The RFP will include all technical specifications required to design a solution. Each RFP will have a period during which potential bidders can ask additional questions.

Rhode Island Energy may require a two-stage proposal process, where the first stage requires a letter of intent describing the proposed concept prior to the second stage proposal with complete technical and financial detail. The objective of this two-stage proposal process is to reduce workload and improve proposals by providing an opportunity for Rhode Island Energy to give feedback and express interest (non-interest) in technically viable (non-viable) proposals.

Results of solicitations – including information about third-party and internally-sourced proposals received – will be reported annually; see Section 7 for more information.

<u>Proposals for Third-Party Solutions</u>

Third-party solution providers may submit proposals for non-wires and non-pipes solutions. RFPs will be posted publicly and can be found by navigating to Rhode Island Energy's System Data Portal. Rhode Island Energy will conduct outreach for each RFP to engage the market in the objective of obtaining a robust set of competitive proposals. Rhode Island Energy will include comprehensive instructions for how potential bidders can submit questions and proposals.

<u>Proposals for Utility-Run Solutions</u>

Program leads representing possibly viable utility-run solutions (i.e., energy efficiency, demand response, renewable energy programs, and energy storage) will be asked to develop proposals in response to the same RFP used to solicit proposals from third-party vendors, subject to the same deadlines, processes, and transparency standards.

<u>Notice to Third-Party Bidders</u>

To aid in transparent processes, the following will be included in each RFP:

"All proposals received by Rhode Island Energy ("RIE") in connection with this Request for Proposals ("RFP") are subject to public disclosure, specifically through filings made by RIE with the Rhode Island Public Utilities Commission ("PUC"). Filings with the PUC are subject to the Rhode Island Access to Public Records Act ("APRA"), R.I. Gen. Laws §38-2-1, et. seq. When making filings with the PUC, RIE will consider all proposals to be public unless RIE, in its discretion, finds that certain portions of information contained within the proposals are exempt from public disclosure pursuant to R.I. Gen. Laws §38- 2-2(4), in which case, RIE may seek confidential treatment from the PUC. Offerors are advised to clearly mark or label "confidential" any portions of information within their proposals that they believe are "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature." When making a filing with the PUC, RIE will take into consideration any information marked by the offeror as confidential. However, broad disclaimers that label the entire proposal as confidential will not help RIE in its APRA analysis and may not be considered."

Step 5. Evaluate Proposals

Rhode Island Energy
a PPL company

With the objective of comparing possible solutions on a level playing field, all possible solutions – whether utility-run or third-party provided – are pursued and evaluated in parallel.

First, the procurement specialist will review all proposals to ensure their completeness. On a case-by-case basis, the procurement specialist may notify bidders of incomplete proposals and allow time for bidders to remedy their proposals. Bidders who do not or cannot submit complete proposals will be notified of their disqualification from the procurement process. The procurement specialist will share all complete proposals with members of the Rhode Island Energy evaluation committee, who will be determined prior to issuing the RFP.

All proposals will be evaluated by all members of the evaluation committee using the same evaluation sequence, evaluation criteria, and weighting. Each member will score each proposal; all member scores will be averaged to obtain the final score. The proposal with the highest score will be tentatively selected; all other bidders will be notified of non-selection.

Evaluation criteria is defined and described in the Least-Cost Procurement Standards, Section 1.3.A:

> *"Least-Cost Procurement shall be cost-effective, reliable, prudent, and environmentally responsible. … System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement."*

Rhode Island Energy adopts these criteria in its evaluation rubric, shown in Figure 8, below. As a threshold step, any proposal that costs more than the best alternative utility reliability procurement solution identified in Step 3 will be removed from consideration. Rhode Island Energy will conduct its comparison of costs using the stipulations defined in Least-Cost Procurement Standards Section 1.3.H.[5]

Figure 8. System Reliability Procurement Evaluation Rubric

Criteria	Description	Weight
Cost	Total project cost is less than or equal to cost of best alternative Utility Reliability Procurement	Go/No-Go
Cost-Effective	Using the Docket 4600 Benefit-Cost Framework, to what extent do benefits outweigh costs?	25; No-Go if BCR- < 1.0
Reliable	To what extent can the proposal reliably resolve the system need?	25; No-Go if deemed not reliable
Prudent	To what extent would advancing the proposal be considered a prudent decision?	25; No-Go if deemed not prudent
Environ-mentally Respon-sible	To what extent is the proposal environmentally responsible?	25; No-Go if not environ-mentally responsible
	Total	**100**

Step 5. Evaluate Proposals

The evaluation committee will review all remaining proposals and score them based on the extent to which they are cost-effective, reliable, prudent, and environmentally responsible. Rhode Island Energy will conduct its evaluation consistent with the requirements provided by the Least-Cost Procurement Standards in Section 1.3, including adherence to the principles for cost tests and resource assessments in Standards Section 1.3.B.[6] Using the stipulations defined in Least-Cost Procurement Standards Sections 1.3.C, 1.3.D, 1.3.E, and 1.3.F, any proposal that is found to be not cost-effective, reliable, prudent, or environmentally responsible will be removed from consideration.[7]

Of all remaining proposals, Rhode Island Energy will tentatively select the proposal with the highest score for continuation in the system reliability procurement process. Outcomes of evaluations – including evaluations of third-party and internally-sourced proposals – will be reported annually; see Section 7 for more information.

Step 5. Evaluate Proposals – Expected Value

Beginning in 2024, Rhode Island Energy will begin exploring how to apply the concept of expected value to its evaluation of proposals for system reliability procurement.

What is expected value?
Expected valuation is a common practice for accounting for probabilities of different outcomes. In essence, the expected value of an action is the sum of its probability-weighted values (see Figure 9).

Expected value may be applied when there are multiple possible outcomes that may result from an action. By applying expected value, we can appropriately internalize the range of likely outcomes; not applying expected value may result in over-emphasizing (under-emphasizing) a particular outcome because of the implicit assumption that outcome will result with 100% (0%) certainty.[8]

-----
[8] For more information about expected valuation, see Appendix 10.
[9] Subject to protection of confidential data and sources.

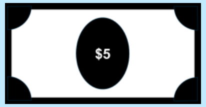
When to apply expected value?
Generally, in the short-term, Rhode Island Energy will apply expected value as a sensitivity analysis in situations where Rhode Island Energy conducts a benefit-cost assessment for investment choices between two alternatives, and for which it is feasible to identify potential outcomes and estimate the probabilities of those outcomes occurring. Rhode Island Energy recognizes that there may be unforeseen complexities that prevent full application of expected value and considers the next few years to be an exploratory, learning experience.

As a first step in this learning experience, Rhode Island Energy will first apply expected value to investment decisions regarding non-wires (non-pipes) solutions relative to wires (pipes) solutions, where the potential outcomes differ in the length of the deferral term of the wires (pipes) solution.

In the longer-term, Rhode Island Energy can potentially apply expected value to more complex decisions, including but not limited to decisions between more than two alternatives and decisions with more than two potential outcomes.

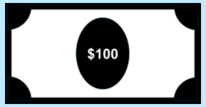
Whenever Rhode Island Energy applies expected value, Rhode Island Energy will document the exact method for each step contained in the methodology, all assumptions, and all justifications or underlying evidence required for a reader to understand and replicate the calculations.[9]

Figure 9. Simple illustration of expected value



99% probability of winning $5
(0.99 X $5.00 = $4.95)

PLUS



1% probability of winning $100
(0.01 X $100.00 = $1.00)

EQUALS

Expected Value of $5.75

If you were to assume winning $5 were the only outcome, then you'd be implicitly assuming 100% probability of winning $5 and 0% probability of winning $100, for an expected value of $5.

If you had to buy a lottery ticket to access these winnings, an economically rational person would be willing to pay up to $5.75 to take the bet that recognizes the small, but non-zero chance of winning $100; up to $0.75 more than an economically rational person who considers only 100% chance of winning $5.

Step 6. Request Regulatory Approval

Rhode Island Energy™
a PPL company

If the evaluation in Step 5 results in a proposal that is less costly than the best alternative utility reliability procurement and is cost-effective, reliable, prudent, and environmentally responsible, then Rhode Island Energy will file for regulatory approval of the system reliability procurement solution.

Figure 10 provides examples of which regulatory avenues Rhode Island Energy may pursue for approval for various solutions, where the wires or pipes solution (yellow row) represents the best alternative utility reliability procurement solution and subsequent rows (gray) represent system reliability procurement. Please note that Figure 10 is not intended to be comprehensive or deterministic; Rhode Island Energy will consider all appropriate regulatory avenues for each system reliability procurement solution.

Figure 10. Examples of filings through which regulatory approval may be requested for an incomplete set of potential solutions to system needs or optimization

Solution Description	Regulatory Filing	Timing of Filing
Wires or Pipes Solution	Electric or Gas Infrastructure, Safety, and Reliability (“ISR”) Plan	Annual filing each December
Third-Party Solution (Technology Agnostic)	SRP Investment Proposal	December, alongside ISR Plan
Utility-Administered Energy Efficiency	SRP Investment Proposal	December, alongside ISR Plan
Utility-Administered Demand Response	SRP Investment Proposal	December, alongside ISR Plan
Utility Owned and Operated Energy Storage	Electric ISR Plan	Annual filing each December
Renewable Energy Incentives	Renewable Energy Growth Program (zonal incentive)	Annual filing each November

Step 7. Implement Solution

Pending regulatory approval, Rhode Island Energy will proceed expeditiously with the system reliability procurement solution. Any third-party solution will require an executed contract between the third party and Rhode Island Energy.

Contracts for third-party system reliability procurement solutions may include terms and conditions covering performance expectations, penalties for non-performance, and data sharing and transparency. An example of such language is below for reference:

"[Vendor] acknowledges that the Rhode Island System Reliability Procurement Program ("Program") is funded by Rhode Island customers through the energy efficiency surcharge on their bills [or other rate mechanism]. [Vendor] agrees to cooperate with Rhode Island Energy ("RIE") and provide any documentation and/or data related to the Program in its possession to RIE for purposes of ensuring that RIE can (i) comply with any directives issued by the Rhode Island Public Utilities Commission ("PUC") or other authorized governmental agency and (ii) respond to any data requests made by the PUC or other governmental agency. [Vendor] also agrees that such documentation and/or data as well as this Agreement may be publicly filed by RIE in regulatory proceedings related to the Program. [Vendor] further agrees to comply with all requirements as reasonably deemed necessary by RIE to ensure that [Vendor] is qualified to serve as a vendor within the Program."

Reporting and Continuous Improvement

Rhode Island Energy is committed to robust procurement and evaluation of system reliability procurement solutions.

To promote transparency, Rhode Island Energy will report results of all procurements, including assessments of the viability of utility-administered solutions. Such reporting will be included within *System Reliability Procurement Annual Reports*. For more information, see Section 7 of this *2024-2026 SRP Three-Year Plan*.

In the spirit of continuous improvement, Rhode Island Energy always encourages and accepts feedback from third-party solution providers, including both bidders and non-bidders. To provide feedback, please email Carrie Gill, Head of Electric Regulatory Strategy: cagill@rienergy.com.

Rhode Island Energy™
a PPL company

Section 3. Electric System Needs and Optimization

Reducing Supply Costs through Electric Demand Response

Rhode Island Energy
a PPL company

System Need or Optimization

Electricity supply costs are partially driven by the high cost of electricity during the few hours of the year when we use the most electricity. During these "peak periods," the most expensive generators are needed to supply enough electricity to meet demand, and their cost is factored into the supply rates customers incur.

Although Rhode Island Energy is an electricity delivery company (akin to FedEx or UPS for delivering packages), we are obliged to help customers who choose not to buy supply from a third-party supplier by buying electricity in bulk on the wholesale market. Rhode Island Energy cares about helping customers access the most affordable electricity and, as such, has identified an opportunity to reduce supply costs by incentivizing demand reductions during peak periods.

---

[10] Rhode Island General Laws 39-1-27.7.b(1)(iii) establishes "demand response, including, but not limited to, distributed generation, back-up generation, and on-demand usage reduction, that 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

SRP Electric System Screening Criteria

This optimization meets all four electric system screening criteria and is, therefore, an opportunity for system reliability procurement:

1. The optimization is not related to an asset condition issue;
2. The optimization is eligible because the optimization requires load relief;
3. The opportunity for system reliability procurement is likely to garner sufficient market interest; and
4. There is adequate time to implement a system reliability procurement solution.

Best Alternative Utility Reliability Procurement Solution

Demand response proposed for this system need is specifically to reduce system-level peak demand. There is no best alternative utility reliability procurement solution at this time.[10,11]

---

system reliability benefits through load control or using on-site generating capability" as an eligible activity within system reliability procurement.

[11] The current demand response program is not capable of managing loads in response to circuit peaks because the current demand response program does not have the necessary inputs, including localized data, to sufficiently manage the distribution system with the existing

---

software/systems. Rhode Island Energy's Grid Modernization Plan analysis identified a need to dispatch demand response resources with an understanding of both localized resource characteristics and system topology. The current system is incapable of doing this for two reasons. First, the current electric system does not have the requisite equipment (sensors, meters, etc.) to provide the data required to understand system topology. Second, the current demand response management system does not have the functionality to pair these two attributes (resource characteristics and system topology). The proposed grid modernization investments include the requisite equipment to provide the data required to understand the system topology and associated limitations on a granular basis. This understanding will provide incremental benefits, such as having the ability to provide localized solutions to address system needs, which will increase the impact of the existing demand response programs. Rhode Island Energy recognizes circuit-focused peak load management is an important functionality for achieving the State's climate and clean energy mandates safely, reliably, and affordably. Rhode Island Energy notes that its proposed grid modernization, our demand response program can be improved to (1) be tied not only to peak load reduction, but also to peak generation management; (2) be tied to distribution system constraints for better infrastructure avoidance; and (3) be integrated and scaled to levels commensurate with State policy drivers. Furthermore, Rhode Island Energy's proposed advanced metering functionality will (i) provide more granular and timely meter data; (ii) improve the Company's ability to dispatch resources; and (iii) allow for more accurate measurement and evaluation of performance. The granular data provided by these investments would be used with the grid modernization investments to provide system-wide real time visibility.

Reducing Supply Costs through Electric Demand Response

Rhode Island Energy
a PPL company

Solicit and Evaluate System Reliability Procurement Proposals

This system reliability procurement opportunity has been addressed since 2019 through the Company's demand response program, branded ConnectedSolutions.[12] As of July 2023, approximately 8,000 customers are participating in ConnectedSolutions through their connected thermostats, battery energy storage systems, and production process curtailments. In aggregate, the participation of these customers has led to a meaningful reduction in peak load resulting in $74 million in costs avoided for our customers. To leverage the value of program continuity, Rhode Island Energy proposes to maintain ConnectedSolutions through 2026.[13]

To administer ConnectedSolutions, Rhode Island Energy partners with a number of curtailment service providers, contracts with a residential demand response vendor, and collaborates with major distribution utilities throughout the region to coordinate demand response events. Rhode Island Energy will continue to coordinate with and grow this ecosystem of third-parties, participants, and partner utilities to increase collective demand reduction and resulting benefits. In the last quarter of 2023, Rhode Island Energy will solicit proposals for a third-party vendor to work with us to achieve a certain level of peak reduction annually for the 2024-2026 period.

Request Regulatory Approval

Rhode Island Energy will request regulatory approval for ConnectedSolutions via a *System Reliability Procurement ("SRP") Investment Proposal* to be filed in December alongside, but separately from, the *Electric Infrastructure, Safety, and Reliability ("ISR") Plan*.[14] The SRP Investment Proposal will include program design specifications, budget, and anticipated participation and impacts. Additional discussion and details about the proposed trajectory of ConnectedSolutions is in Appendix 4.

Implement Solution

Pending regulatory approval, Rhode Island Energy will reopen ConnectedSolutions for the 2024 peak demand season, beginning in Spring 2024. Rhode Island Energy will report the resulting impacts in its *SRP Annual Report*.[15]

---

[12] ConnectedSolutions had previously been housed within filings related to energy efficiency (e.g., *2021-2023 Energy Efficiency Three-Year Plan*, *2023 Energy Efficiency Annual Plan*). Beginning in 2024, Rhode Island Energy will include ConnectedSolutions within filings related to system reliability procurement instead.

[13] Although this *2024-2026 SRP Three-Year Plan* only pertains to activities through 2026, Rhode Island Energy does envision the continuation of a demand response program past 2026, subject to future design modification and appropriate regulatory review.

[14] As is recommended by the Least-Cost Procurement Standards (2023 version) Section 5.5.A.

[15] For more information on annual reporting, see Section 7.

Improving Reliability in Woonsocket

System Need or Optimization
In the Blackstone Valley South Area Study, Rhode Island Energy identifies a system need on a feeder in Woonsocket (excerpt below).[16]

Electric System Screening Criteria
This optimization meets all four electric system screening criteria and is, therefore, an opportunity for system reliability procurement:

1. The optimization is not related to an asset condition issue;
2. The optimization is eligible because the optimization requires load relief;
3. The opportunity for system reliability procurement is likely to garner sufficient market interest; and
4. There is adequate time to implement a system reliability procurement solution.

Best Alternative Utility Reliability Procurement Solution
As discussed in the Area Study, above, the best alternative utility reliability procurement solution involves reconductoring approximately one mile of cable. This solution is anticipated to cost $1.1 million.

Next Step: Solicit System Reliability Procurement Proposals
Rhode Island Energy plans to develop and issue an RFP for this system reliability procurement opportunity in 2024.

Feeder 112W43 Reconductoring Options 1

Reliability can be improved by reconductoring ~5,340' of cross arm and armless to spacer cable along West Wrentham Road from pole #35 to pole #82. Refer to Appendix 7.6 for detailed plan development drawings. The wires solution should be further investigated. An infrared scan of the OH distribution equipment was completed in May 2021 and the issues have been resolved. Tree trimming was performed in FY20.

Spend	Cost ($M)
CapEx	$ 1.000
OpEx	$ 0.020
Removal	$ 0.080
Total	$ 1.100

Feeder 112W43 Non-wire Alternative Option 2

There is approximately 94% of total feeder connected kVA and 93% of total feeder customers past the reconductored section mentioned in Option 1. Based on the assessment of applicability of non-wires alternatives, the preferred solution may be a good candidate to go to market for an NWA solution. The NWA solution is currently being evaluated internally. Due to the ongoing NWA review, the wires solution cost identified above will not be included in the cost summary table below and in section 7.

[16] See page 34, available here: https://systemdataportal.nationalgrid.com/RI/documents/Blackstone_Valley_South_Area_Study_Report_Rev1_final_signed_redacted.pdf

Rhode Island Energy™
a PPL company

Section 4. Gas System Needs and Optimization

Gas Demand Response

System Need or Optimization

During the coldest days of the year when our system is near daily or hourly peak demand, upstream or on-system constraints may result in demand exceeding available pipeline capacity in certain areas on the system. Historically, Aquidneck Island has been a capacity constrained area that is closely evaluated by Rhode Island Energy with respect to gas procurement and system planning.

SRP Gas System Screening Criteria

This system need is not related to an asset replacement investment. It qualifies as an eligible system need or optimization, is likely to garner sufficient market interest, and there is adequate time to implement a system reliability procurement solution. Therefore, this system need passes the gas system screening criteria and is a system reliability procurement opportunity.

Best Alternative Utility Reliability Procurement Solution

Gas demand response is a pilot program. We are trying to understand the scalability of the program and the degree to which it might offset a utility reliability procurement. Hence, it is not appropriate to evaluate the pilot program against a utility reliability procurement solution at this time.

Solicit System Reliability Procurement Proposals

For this system need, Rhode Island Energy administers a demand response pilot program for large, firm commercial and industrial customers, specifically those customers with gas equipment that can be curtailed without compromising safety.

The demand response pilot program incentivizes the deferral or avoidance of gas use during peak periods through adjusting thermostat settings or by temporarily switching to an alternative, back-up heating source. Testing the efficacy of gas demand response will allow Rhode Island Energy to understand gas demand response's impact on gas system needs and optimization, customer interest, effectiveness of incentive levels, and scalability of the program, as well as its potential applicability to other customer classes.

Because the gas demand response program is in the pilot stage and designed to test the benefits of reducing gas system peak demand, customer adoption of gas demand response, the incentive levels required drive participation, and RI Energy's role in influencing market adoption, it is, by nature of its design and goals, necessary for the Company to administer the program. Following the Gas DR Pilot, Rhode Island Energy will evaluate whether there is value in launching a full-scale demand response program.

Evaluate Possible Solutions

Gas demand response may have the potential for many system benefits and value streams, such as alleviating local distribution system constraints, increasing system flexibility, delaying infrastructure investments, and providing revenue to participants. The gas demand response pilot program will target 40-50 dekatherms ("Dth") of hourly peak demand reduction in the winter of 2023/2024. While gas demand response does not directly address climate change, greenhouse gas emissions may be reduced due to participation during peak demand events and may help avoid gas infrastructure investments.

---

[17] See Section 7 for more information about annual reporting.

Gas Demand Response

Rhode Island Energy
a PPL company

<u>Request Regulatory Approval</u>

Rhode Island Energy will request regulatory approval for its gas demand response pilot program via a *System Reliability Procurement Investment Proposal* to be filed in November, separate from the *Gas Infrastructure, Safety, and Reliability ("ISR") Plan* to be filed in December. *The SRP Investment Proposal* will include program design specifications, budget, and anticipated participation and impacts. We discuss further details about the trajectory of the demand response program in Appendix 4.

<u>Implement Solution</u>

In its *SRP Investment Proposal*, Rhode Island Energy will propose the continuation of – and potential expansion to include residential and small-business customers with hybrid gas-electric heating systems – its gas demand response pilot program during peak gas demand season beginning in winter 2024. However, gas demand response hasn't provided the level of relief anticipated due to lack of performance during called events and low customer interest so enhancements are needed to create a more effective program. The learnings for the pilot program going forward will focus on how to increase program enrollment, participation during call events, and potential expansion of the program beyond large commercial and industrial customers. Aquidneck Island will continue to be a particular focus, but other areas with similar capacity constraints will be evaluated. Rhode Island Energy will report the resulting impacts of its demand response program in its *SRP Annual Reports*.

Section 5. Market and Stakeholder Engagement

Engagement for Solicitations

Rhode Island Energy
a PPL company

In service to the objective of evaluating all possible solutions on a level playing field, Rhode Island Energy is interested in ensuring all competitive proposals are presented. To mitigate risk of an otherwise viable solution not being proposed due to lack of awareness about an RFP, Rhode Island Energy will conduct outreach for its system reliability procurement RFPs in the following ways:

1. Rhode Island Energy will post all RFPs for system reliability procurement publicly on the System Data Portal website.
2. Rhode Island Energy will email its list of third-party vendors when the RFP is issued and in reminder prior to the due date.
3. Rhode Island Energy will notify the System Reliability Procurement Technical Working Group so that members may conduct outreach to their constituents and colleagues.
4. Rhode Island Energy will notify the Energy Efficiency Technical Working Group so that members may conduct outreach to their constituents and colleagues.
5. Rhode Island Energy will make announcements at meetings of the Energy Efficiency and Resource Management Council and the Distributed Generation Board.

Rhode Island Energy welcomes ideas from potential bidders for other avenues of outreach that would be beneficial.

System Data Portal

Rhode Island Energy™
a PPL company

Rhode Island Energy maintains an interactive website where third parties can access information about the electric distribution system, called the "System Data Portal." The primary objective of the System Data Portal is to use information to nudge development of distributed energy resources to locations on the grid that provide relatively more operational value. An ancillary benefit is that developers can gain insight into potential development locations that may result in relatively low interconnection costs and/or relatively quick interconnection times. Appendix 3 contains more information about how to use the System Data Portal, including specific use cases for various stakeholders including distributed generation developers, electric vehicle charging infrastructure developers, and building developers.

Rhode Island Energy is in the process of migrating the System Data Portal from National Grid's servers to PPL's servers, expected to be complete by May 2024. This migration will preserve all key components of the System Data Portal, including Company Reports, Distribution System Data Map, Heat Map, and Hosting Capacity Map, all of which will be updated by the end of the first quarter of each year on an ongoing basis.

Rhode Island Energy will make the following changes and improvements to the System Data Portal:

- Solicitations for System Reliability Procurement will be housed within the Company Reports tab instead of the tab currently titled "NWA." By housing all relevant materials together (i.e., solicitations, area studies, and the *2024-2026 SRP Three-Year Plan*), we hope third-party solution providers and potential bidders can more easily access pertinent information for beneficial development of distributed energy resources and successful proposals for non-wires solutions.

- Equivalent materials for the gas distribution system and solicitations for non-pipes solutions will be added to the Company Reports tab.

- Rhode Island Energy will remove the fleets layer from the heat map, but add a map showing loading hosting capacity. The original objective of this layer was to help third parties identify fleets that could potentially be electrified. However, there is no compelling evidence that the fleet layer is actively used and there are administrative challenges with updating the layer. Instead, we will add a full map tab showing loading hosting capacity on each feeder. This layer will provide third parties information about which feeders may have the capacity to accommodate electric vehicle charging infrastructure with relatively low interconnection cost.

- Rhode Island Energy will remove the tab "SLR," which shows projections of sea level rise using data sourced from the National Oceanic and Atmospheric Administration. To aid third parties in developing distributed energy resources in locations with lower climate risk, Rhode Island Energy will add layers to each map tab that allow users to toggle on/off map layers from Rhode Island's STORM TOOLS, a suite of maps that show coastal flooding for various levels of storm and sea level rise that is used by the Coastal Resources Management Council. Rhode Island Energy recognizes the importance of climate resilience and climate adaptation for our energy resources and welcomes suggestions for other useful map overlays on an ongoing basis.

System Reliability Procurement Technical Working Group

The SRP Technical Working Group (TWG) is an external stakeholder group convened and administered by Rhode Island Energy for the sole purpose of advising Rhode Island Energy on matters related to System Reliability Procurement, as defined by Least-Cost Procurement Statute under RIGL 39-1-27.7. The SRP TWG is not a statutory or regulatory requirement, nor is the group public. Members of the SRP TWG include the Rhode Island Division of Public Utilities and Carriers, Rhode Island Office of Energy Resources, Energy Efficiency and Resource Management Council, Acadia Center, Green Energy Consumers Alliance, Northeast Clean Energy Coalition, and Conservation Law Foundation.[18] Rhode Island Energy will continue to convene the SRP TWG throughout 2024-2026. Topics of discussion for this time period may include but are not limited to process improvements for system reliability procurement solicitations and evaluations, review of SRP Investment Proposals and SRP Annual Reports, improvements for the System Data Portal, and other topics to be identified. For more information about the SRP TWG, please email Carrie Gill at cagill@rienergy.com.

[18] While Commerce RI, Rhode Island Office of the Attorney General, and Rhode Island Infrastructure Bank have been members and are welcome to continue to participate, there are currently no representatives from these organizations who are active in the SRP TWG.

Rhode Island Energy™
a PPL company

Section 6. Performance Incentive Plan

Performance Incentive Plan

Rhode Island Energy proposes performance incentive structures for (i) demand response and (ii) implementation of a system reliability procurement solution. Both incentives are structured as shared savings, where the demand response performance incentive shares avoided supply costs and system reliability procurement shares avoided distribution costs.

Through system reliability procurement, Rhode Island Energy is creating value. The Company proposes to share this value between customers and shareholders, thereby accomplishing the Company's dual mission of delivering safe, affordable, reliable, sustainable energy to customers and long-term value to shareholders.

Please note that the incentive structures below are conceptual; Rhode Island Energy will propose specific performance incentives aligned with this structure in each of its *SRP Investment Proposals*.

<u>Demand Response Performance Incentive</u>
Rhode Island Energy proposes a dollar per megawatt peak reduction performance incentive for its demand response achievements. The level of incremental incentive is tied to quantitative net benefits, as described below. The objective is to share quantifiable cash savings with customers.

Quantitative net benefits
- Electric Savings: Energy
- Electric Savings: Capacity
- Resource Benefits: Electric Energy
- Resource Benefits: Electric Energy DRIPE
- Resource Benefits: Electric Capacity
- Less: Program Costs

[20] This proposal is similar to the System Efficiency Performance Incentive Mechanism developed and approved via Docket No. 4770, except that it is specific to system peak reduction achieved through demand response.

Performance Incentive Plan

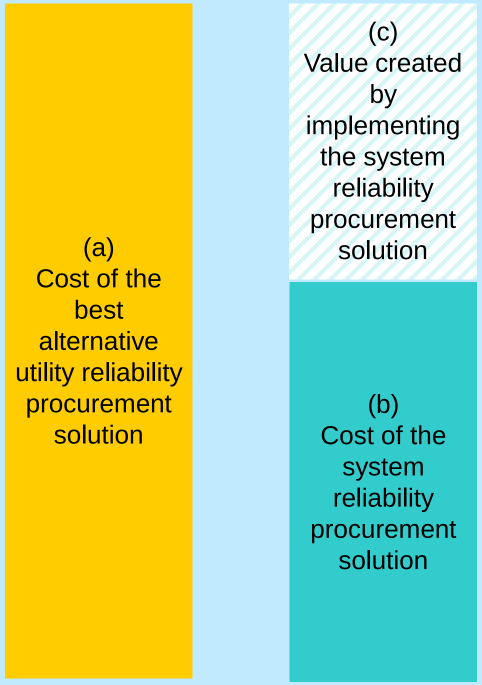
<u>System Reliability Procurement Performance Incentive</u>

Rhode Island Energy proposes a shared savings mechanism for successfully implementing system reliability procurement solutions. Savings is defined as avoided costs between the system reliability procurement solution and the best alternative utility reliability procurement solution, where 80 percent is allocated to customers and 20 percent is earned by the Company on an annual basis.

Rhode Island Energy additionally proposes a minimum performance incentive for the successful implementation of each system reliability procurement solution, commensurate with the lost return its shareholders would have earned on the best alternative utility reliability procurement solution. This minimum ensures that there is no structural earnings incentive for one type of solution over another. Figure x, below, illustrates the share value approach to a performance incentive.

When the Company files its proposed system reliability procurement solution, the filing will contain details of the best alternative reliability procurement solution, including annual financials, for full regulatory scrutiny. The same details will be provided for the proposed system reliability solution. The Company will request regulatory approval of the performance incentive, implying regulatory review and approval of the specific financials of the best alternative utility reliability procurement solution and the proposed system reliability procurement solution. The performance incentive will be calculated and included within each annual system reliability procurement report, using actual data of the prior year's expenses on the approved system reliability procurement solution relative to the best alternative utility reliability procurement solution. This performance incentive will be recovered via the same cost recovery mechanism used to fund the proposed system reliability procurement solution.

Figure 10. System Reliability Procurement Performance Incentive



Performance incentive =
MAX {allowed return on best alternative utility reliability procurement solution, 20% * (c)}

Section 7. Annual Reporting

Annual Reporting

Rhode Island Energy will submit an SRP Annual Report to the Rhode Island Public Utilities Commission by June 1 of each year covering activities completed within the prior calendar year (e.g., the 2024 SRP Annual Report will cover activities conducted January 1 through December 31, 2024, and will be submitted by June 1, 2025). With the dual objectives of transparently reporting activities to interested stakeholders and holding the Company accountable, each annual report will include the following information:

- Results of each step included in the SRP process described in Section 2;
    - Where results of screening for electric and gas system reliability procurement opportunities, with any opportunities added to a comprehensive listing of opportunities with summary information about system needs or optimization and next step/date of next step (akin to the descriptions provided in Sections 3 and 4);
- Results of Steps 4-5 (solicitation and evaluation) include proposals and their evaluation outcomes for internally-sources system reliability procurement solutions that did or did not advance to Step 6 (regulatory review);
- Calculation of performance incentives, as applicable, resulting from successful implementation of system reliability procurement (Step 7)
- A summary of any major changes to the System Data Portal (beyond routine updating of data);
- A summary of engagement with the SRP Technical Working Group; and
- A description of any proposed changes to process, funding, performance incentive, annual reporting, or any other system reliability procurement activity with a justification for the proposed change and any request regulatory ruling related to the proposed change.

Section 8. Consistency with LCP Standards

Consistency with LCP Standards

In this section, Rhode Island Energy discusses how the 2024-2026 SRP Three Year Plan –specifically the proposed system reliability procurement process – is consistent with the requirements of Least-Cost Procurement Standards Section 1.3. Key excerpts are copied below for easy and direct reference.

Rhode Island Energy will include detailed discussion and documentation (where appropriate) specific to each System Reliability Procurement Investment Proposal to evince its adherence to Least-Cost Procurement Standards Section 1.3.

<u>Least-Cost Procurement Standards Section 1.3.A</u>
"Least-Cost Procurement shall be cost-effective, reliable, prudent, and environmentally responsible. … System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement."

The evaluation step of the system reliability procurement process described in Section 2 Step 5 of this Plan is consistent with Standards Section 1.3.A because the evaluation criteria are structured such that any proposed system reliability procurement solution that is not cost-effective, reliable, prudent, environmentally responsible, and lower than the cost of the best alternative utility reliability procurement solution is removed from further consideration. The proposed system reliability procurement process and evaluation criteria guarantee consistency with Standards Section 1.3.A.

<u>Least-Cost Procurement Standards Section 1.3.B</u>
"When preparing any cost test or resource assessment, including the RI Test, the following principles will be applied: i. Supply-side and demand-side alternative energy resources shall be compared in a consistent and comprehensive manner. ii. Cost tests shall be created using the RI Framework and account for applicable policy goals, as articulated in legislation, PUC orders, regulations, … assessed. iv. Cost tests shall be symmetrical, for example, by including both costs and benefits for each relevant type of impact. v. Analyses of the impacts of investments shall be forward-looking, capturing the difference between costs and benefits that would occur over the life of the investments with those that would occur absent the investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis. vi. Cost tests shall be completely transparent and should fully document and reveal all relevant inputs, assumptions, methodologies, and results."

The system reliability procurement process described within Section 2 of this Plan includes a step for evaluating system reliability procurement proposals. Within this step, Rhode Island Energy describes its adherence to the principles put forth in Standards Section 1.3.B. In this manner, the Plan is consistent with this requirement of the Standards.

Consistency with LCP Standards

Rhode Island Energy
a PPL company

<u>Least-Cost Procurement Standards Sections 1.3.C-F</u>
These sections stipulate criteria that shall or may be used in the assessment of the extent to which system reliability procurement solutions are cost-effective, reliable, prudent, and environmentally responsible.

The stipulations for determining cost-effectiveness are built into the system reliability procurement process in evaluation of system reliability procurement project proposals. Rhode Island Energy describes its adherence to the Least-Cost Procurement Standards in Section 2 Step 5.

<u>Least-Cost Procurement Standards Section 1.3.H</u>
"Lower than the cost of the best alternative Utility Reliability Procurement i. The distribution company shall compare the cost of System Reliability Procurement measures, programs, and/or portfolios to the cost of the best alternative Utility Reliability Procurement option using all applicable costs enumerated in the RI Framework. The distribution company shall provide specific costs included in the Cost of System Reliability Procurement. ii. At a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test. iii. The distribution company shall describe which costs in the RI Framework were included in the cost of System Reliability Procurement and which costs are included in the alternative Utility Reliability Procurement. For any categories that are not included in either, the distribution company shall describe why these categories are not included."

Rhode Island Energy explicitly commits to adhere to Least-Cost Procurement Section 1.3.H in its assessment of the cost of the system reliability procurement solution relative to the best alternative utility reliability procurement solution.[20]

---
[20] Least-Cost Procurement Section 1.3.H is the relevant section for System Reliability Procurement; Section 1.3.G is relevant for Energy Efficiency and, as such, is not included for discussion herein.

Section 9. Request for Ruling

Request for Ruling – *forthcoming*

In accordance with Least-Cost Procurement Standards (2023) Chapter 4.5 (Docket No. 23-07-EE), Rhode Island Energy respectfully requests that the Commission

A. approve screening requirements and implementation plans described in Sections 2-5;

B. approve annual reporting requirements described in Section 7; and

C. approve the performance incentive plan described in Section 6.

Please note that Rhode Island Energy is not requesting any ruling on the draft *System Reliability Procurement Investment Proposals* contained in Appendix 4 at this time; final versions of these proposals will be filed with the Commission for review and approval separately.

Appendices

Appendices (not included herein)

Appendix 1.	Slide Deck Format of *2024-2026 SRP Three-Year Plan*
Appendix 2.	Notes on Terminology
Appendix 3.	Legal and Regulatory Basis
Appendix 4.	Preliminary Conceptual Drafts of *SRP Investment Proposals*
Appendix 5.	System Data Portal
Appendix 6.	Electric System Reliability Procurement Benefit-Cost Assessment Model
Appendix 7.	Electric System Reliability Procurement Technical Reference Manual
Appendix 8.	Gas System Reliability Procurement Benefit-Cost Assessment Model
Appendix 9.	Gas System Reliability Procurement Technical Reference Manual
Appendix 10.	Expected Valuation

Appendix 2. Notes on Terminology

Least-Cost Procurement Standards

The version of the Least-Cost Procurement Standards in effect for 2024-2026 is the version adopted by Order [TBD] in Docket No. 23-07-EE: https://ripuc.ri.gov/Docket-23-07-EE.

The following definitions are excerpted from the Least-Cost Procurement Standards for convenient reference:

> System Reliability Procurement
> Procurement to meet or mitigate a gas or electric system need or optimization from a party other than the gas or electric utility[23] that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[24]
>
> Utility Reliability Procurement
> Procurement to meet or mitigate a gas or electric system need or optimization that is not System Reliability Procurement is a utility investment.[25]
>
> System Needs
> i. Electric System Needs: Needs to serve both customer load and customer generation, including, but not limited to, system capacity (normal and emergency), voltage performance, reliability performance, protection coordination, fault current management, reactive power compensation, asset condition assessment, distributed generation constraints, operational considerations, and customer requests.
> ii. Gas System Needs: Needs to serve customers, including, but not limited to, system capacity (normal and emergency), pressure management, asset condition assessment, gas service that supports electric distributed generation, and operational considerations.
>
> Optimization of System Performance
> Improvement of the performance and efficiency[26] of the gas or electric system that includes enhanced reliability, peak load reduction, improved utilization of both utility and non-utility assets, optimization of operations, and reduced system losses.

[23] A utility proposal to own and operate non-traditional investment or new operations and maintenance services, such as new voltage-regulation equipment, battery storage, or vegetation management, and any vendor services associated with such investment or service, shall not be considered System Reliability Procurement per this definition. Such investments and services are, however, still subject to the Guidance Document issued in Docket No. 4600A.

[24] Including, but not limited to, the resources named in R.I. Gen. Laws § 39-1-27.7(a)(1)(i)-(iii).

[25] For example, many such Utility Reliability Procurement investments and operations are proposed in annual Infrastructure, Safety, and Reliability Plans filed pursuant to R.I. Gen. Laws § 39-1-27.7.1(c)(2).

[26] Efficiency includes both long- and short-term cost efficiency.

Rhode Island Energy further annotates the following terminology to aid in understanding of this *2022 SRP Year-End Report*:

<u>Non-Wires/Non-Pipes Alternative</u>
Outdated terms referring to non-wires/non-pipes solution.

<u>Non-Wires/Non-Pipes Solution</u>
A solution that satisfies a System Need or Optimization of System Performance through means other than utility-owned infrastructure.

<u>Non-Wires/Non-Pipes Opportunity</u>
A System Need or Optimization of System Performance that may be satisfied via a Non-Wires/Non-Pipes Solution (i.e., the electric or gas screening criteria has been met).

<u>Non-Wires/Non-Pipes Project Proposal</u>
A proposal for a specific Non-Wires/Non-Pipes Solution for a specific Non-Wires/Non-Pipes Opportunity (i.e., such as a proposal submitted in response to a Request for Proposals).

<u>Non-Wires/Non-Pipes Project</u>
A specific Non-Wires/Non-Pipes Solution for a specific Non-Wires/Non-Pipes Opportunity (i.e., such as a project in the process of being constructed, installed, or otherwise implemented).

<u>Non-Wires/Non-Pipes Program</u>
The process by which Rhode Island Energy identifies non-wires/non-pipes opportunities, solicits and evaluates non-wires/non-pipes project proposals, and submits funding requests with relevant justification and documentation for non-wires/non-pipes projects.

<u>Wires/Pipes Solution</u>
A solution that satisfies a System Need or Optimization of System Performance through utility-owned infrastructure.

<u>SRP Investment Proposal</u>
A filing describing a Non-Wires/Non-Pipes Project per Chapter 5 of the Least-Cost Procurement Standards.

<u>Utility Performance Incentive</u>
Shared value between customers and Company shareholders.

Appendix 3. Legal and Regulatory Basis

Least-Cost Procurement Statute [27]

System reliability procurement is contemplated in Rhode Island's Least-Cost Procurement statute. Some key relevant excerpts from this statute are below for convenient reference.

"§ 39-1-27.7. System reliability and least-cost procurement.

(a) 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 and natural gas energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent, and environmentally responsible.

(b) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement that shall include standards and guidelines for:

(1) System reliability procurement, including but not limited to:

(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, that 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, that 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;

(iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) For qualifying distributed generation, demand response, and renewable energy resources; (B) For net metering; (C) For back-up power and/or standby rates that reasonably facilitate the development of distributed generation; and (D) For such other matters as the commission may find necessary or appropriate.

(4) Each electrical and natural gas distribution company shall submit to the commission on or before September 1, 2008, and triennially on or before September 1 thereafter through September 1, 2028, a plan for system reliability and energy efficiency and conservation procurement…"

[27] RIGL 39-1-27.7 http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM

Least-Cost Procurement Standards – Chapter 4

Chapter 4 of the Rhode Island Public Utilities Commission's "Least-Cost Procurement Standards," approved and adopted pursuant to Order No. [TBD] in Docket No. 23-07-EE (LCP Standards), describes the intent, purpose, plan design and principles, content, orders, and timing of *SRP Three-Year Plans*. This Chapter is copied below for convenient reference.

4.1 Intent

A. This Chapter provides standards and guidelines for System Reliability Procurement Plans filed with the PUC pursuant to R.I. Gen. Laws § 39-1-27.7(c)(4).

4.2 Purpose

A. The Three-Year System Reliability Procurement Plan (Three-Year SRP Plan) shall describe general planning principles and potential areas of focus for System Reliability Procurement for the three years of implementation, beginning with January 1 of the following year.

B. The Three-Year SRP Plan shall provide screening criteria for System Reliability Procurement opportunities that may supplant Utility Reliability Procurement and a proposal for how such screening criteria will be included in system planning.

C. The Three-Year SRP Plan will provide strategies and technologies the distribution company intends to employ or consider employing over the next three years pursuant to R.I. Gen. Laws § 39-1-27.7 and these standards.

D. The Three-Year SRP Plan will explain in summary how identical, similar, and related investments across programs contributed incrementally to the state energy policies and goals for the natural gas and electric systems.

E. The Three-Year SRP Plan will describe the procurement process for market-sourced System Reliability Procurement solutions.

F. The Three-Year SRP Plan will describe the evaluation process for System Reliability Procurement.

4.3 General Plan Design and Principles

A. In order to meet Rhode Island's gas and electric energy system needs and policy goals in a manner consistent with R.I. Gen. Laws §39-1-27.7, Three-Year SRP Plans should include both a broad consideration of needs and goals and broad consideration of solutions to these needs and goals in order to encourage optimal investment by the distribution company.

B. The Three-Year SRP Plan should be integrated with the distribution company's distribution planning process and be designed, where possible, to complement the objectives of Rhode Island's energy policies and programs as described in Section 3.2.A.

C. The Three-Year SRP Plan should be designed so that potential non-utility solution providers can understand how and when the distribution company makes decisions to implement System Reliability Procurement in lieu of Utility Reliability Procurement.

4.4 Content

A. The Three-Year Plan shall contain sections that describe how it meets the purposes described in Section 4.2, including but not limited to:

i. proposed screening criteria for System Reliability Procurement, a description of the type(s) of system need(s) that may be addressed with System Reliability Procurement (e.g., system capacity), and a proposal for how such screening criteria will be included in system planning.

ii. for each specific system need that meets the screening criteria in 4.4.A.i, the distribution company shall provide:

a. a description of the specific system need and how it was identified in the system planning process, and when the distribution company expects to need to implement the best alternative Utility Reliability Procurement investment;

b. a description of how the specific system need can be addressed or mitigated through System Reliability Procurement;

c. description of which specific System Reliability Procurement investment(s) will be pursued each year until the best alternative Utility Procurement investment needs to be implemented;

d. initial identification of, or proposal of, cost recovery mechanisms for the System Reliability Procurement investment identified pursuant to paragraph c above and, where possible, specific references to dockets or recurring program reviews,[28] including, when applicable, filings to be made pursuant to Chapter 5 of these Standards;

e. references to where other public information about the specific system need is available;

[28] If a cost-recovery proposal is in the future, the docket will not be known, but the program, such as "Annual EE Plan for 2023" may be known.

iii. proposed strategies that can help the distribution company pursue System Reliability Procurement, such as activities that animate the market or reduce market barriers;

iv. proposed general procurement processes used by the company to procure market sourced System Reliability Procurement and Utility Reliability Procurement;

v. proposed general evaluation process for choosing among System Reliability Procurement options or market-based solutions; and

B. The Three-Year SRP Plan will include an annual reporting plan on the implementation of the Three-Year SRP Plan and investments made under System Reliability Procurement during the Three-Year SRP Plan period.

C. The Three-Year SRP Plan will include a discussion of how the Plan is consistent with the requirements of Section 1.3.

D. Performance Incentive Plan Structure

i. The distribution company may propose incentive structures for System Reliability Procurement for effect during the Three-Year SRP Plan.

E. Testimony

i. To the extent applicable, the distribution company will pre-file testimony on the following:

a. Cost-Effectiveness of measures, programs, and portfolios;

b. Prudence, specifically those elements of prudence described in Section 1.3.E.i.e. Given the overlap of Section 1.3.E.e and the issues of parity described in Section 3.2.M, testimony on prudence should also address issues of parity;

c. Reliability;

d. Environmental Responsibility; and

e. Cost(s) of the best alternative Utility Reliability Procurement investment(s) compared to the System Reliability Procurement investment(s) measures, programs, and portfolios.

ii. Prefiled testimony will also state what approvals for the Three-Year SRP Plan the distribution company is requesting from the PUC.

4.5 PUC Orders

A. The PUC will approve screening requirements and implementation plans that meet the Standards herein.

B. The PUC will approve annual reporting requirements that meet the standards herein.

C. The PUC may approve a three-year performance incentive plan for System Reliability Procurement.

D. The PUC will order adoption of any other proposals supported by the Plan and consistent with Least-Cost Procurement, and all applicable statutes, rules, and policies.

4.6 Timing

A. The distribution company will file the Three-Year SRP Plan on or before November 21, 2020 and triennially thereafter."

Least-Cost Procurement Standards – Section 1.3
Section 1.3 of the Rhode Island Public Utilities Commission's "Least-Cost Procurement Standards," approved and adopted pursuant to Order No. [TBD] in Docket No. 23-07-EE (LCP Standards), establishes principles and stipulations for the assessment of cost, cost-effectiveness, reliability, prudency, and environmental responsibility of system reliability procurement solutions. This Chapter is copied below for convenient reference.

A. "Least-Cost Procurement shall be cost-effective, reliable, prudent, and environmentally responsible. Least-Cost Procurement that is Energy Efficiency and Conservation Procurement shall also be lower than the cost of additional energy supply. System Reliability Procurement shall be lower than the cost of the best alternative Utility Reliability Procurement.

B. When preparing any cost test or resource assessment, including the RI Test, the following principles will be applied:

   i. Supply-side and demand-side alternative energy resources shall be compared in a consistent and comprehensive manner.

   ii. Cost tests shall be created using the RI Framework and account for applicable policy goals, as articulated in legislation, PUC orders, regulations, guidelines, and other policy directives.

   iii. Cost tests shall account for all relevant, important impacts, even those that are 5 difficult to quantify and monetize. Where applicable cost or benefit categories cannot be quantified, such categories shall be qualitatively assessed.[29]

   iv. Cost tests shall be symmetrical, for example, by including both costs and benefits for each relevant type of impact.

[29] Qualitative assessments may include relative descriptions of magnitude and direction.

v. Analyses of the impacts of investments shall be forward-looking, capturing the difference between costs and benefits that would occur over the life of the investments with those that would occur absent the investments. Sunk costs and benefits are not relevant to a cost-effectiveness analysis.

vi. Cost tests shall be completely transparent and should fully document and reveal all relevant inputs, assumptions, methodologies, and results.

C. Cost-Effective

i. The PUC shall determine cost-effectiveness in a manner consistent with the PUC's Guidance Document issued in Docket No. 4600A.

ii. The distribution company shall assess the cost-effectiveness of measures, programs, and portfolios of Least-Cost Procurement. All categories of the RI Test are applicable to cost-effectiveness, although some categories may have no or unknown value. The distribution company shall assess cost-effectiveness using, at a minimum, the following two cost-effectiveness analyses:

a. An analysis that, for categories with value or cost that is shared between Rhode Island Energy and other jurisdictions (both within the state and region), presents benefits and costs without allocating them between Rhode Island Energy and other jurisdictions;

b. An analysis that, for categories with value or cost that is shared between Rhode Island Energy and other jurisdictions (both within the state and region), presents only those benefits and costs that will be allocated to Rhode Island Energy.

iii. The distribution company shall provide the specific benefit- and cost-factors included in determining the RI Test ratios.

iv. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of greenhouse gas emissions mitigation (measured in $CO2$ equivalents) as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative, Rhode Island Renewable Energy Standard and Rhode Island Act on Climate, and 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. The RI Test shall also include the costs and benefits of other emissions and their generation or reduction through Least Cost Procurement. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above.

v. Benefits and costs that are projected to occur over the term of the Least-Cost Procurement investment shall be stated in present value terms in the RI Test calculation, using a discount rate that appropriately reflects the risks of the investment of customer funds in Least-Cost Procurement. Energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk.

D. Reliable

i. The distribution company shall assess the

a. ability of Least-Cost Procurement investments to meet the energy supply or delivery system needs.

b. ability of previous investments, including identical or similar investments, to support the conclusion that a new investment is reliable, and

c. potential for implementation issues, including available workforce, market continuity, program scalability.

ii. As applicable, the distribution company also shall assess an investment's

a. ability to meet specific identified system needs;

b. anticipated reliability as compared to alternatives;

c. operational complexity and flexibility;

d. resiliency of the system;

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

f. risks associated with customers' behavior, responsiveness, and ability to potentially modify usage at certain times and seasons; and

g. relative changes in other risks that are applicable to the investment, such as reduced (or increased) public safety risk.

The distribution company shall supply any other information that the company believes supports a finding that an investment is reliable.

E. Prudent

i. The distribution company shall assess:

a. how the investment supports the goals of the electric or natural gas system and the purposes of Least-Cost Procurement.
b. potential for synergy savings based on alternatives that address multiple needs;

c. how the entire investment proposal affects the risks of ratepayers and the distribution company;

d. how the investment effectively uses available funding sources and integrates with energy programs and policies; and

e. how the investment is equitable in consideration of the allocation of costs, the allocation of benefits, customer access, and customer participation. This shall be done by, at minimum, assessing which groups have historically received disproportionately lower benefits from LCP investments and by presenting other appropriate, quantifiable metrics that describe how an investment is equitable.

ii. The distribution company shall provide rate impacts to a range of customer types and usage levels, and shall provide bill impacts, and shall provide how these impacts were considered in the proposed investment.

iii. The distribution company may provide additional cost tests to support a finding that an investment is prudent.

iv. The distribution company shall supply any other information that the company believes supports a finding that an investment is prudent.

F. Environmentally Responsible

i. The distribution company shall assess how investment complies with State environmental and climate policies and shall properly value environmental and climate costs and benefits.

ii. The distribution company shall assess how the investment affects environmental and climate pollution, where applicable, at a local, regional, and global scale.

G. Lower than the Cost of Additional Supply (omitted)

H. Lower than the cost of the best alternative Utility Reliability Procurement

i. The distribution company shall compare the cost of System Reliability Procurement measures, programs, and/or portfolios to the cost of the best alternative Utility Reliability Procurement option using all applicable costs enumerated in the RI Framework. The distribution company shall provide specific costs included in the Cost of System Reliability Procurement.

ii. At a minimum, the comparison shall include the applicable cost categories in a Total Resources Cost Test.

iii. The distribution company shall describe which costs in the RI Framework were included in the cost of System Reliability Procurement and which costs are included in the alternative Utility Reliability Procurement. For any categories that are not included in either, the distribution company shall describe why these categories are not included."

Appendix 4. Preliminary Conceptual Drafts of SRP Investment Proposals

- Please note that the drafts contained in this appendix are the preliminary conceptual proposals from October 2023. Rhode Island Energy anticipates filing its SRP Investment Proposal for a gas demand response pilot program in November 2023, and its SRP Investment Proposal for electric demand response in December 2023.

Reducing Energy Supply through Electric Demand Response

System Reliability Procurement Investment Proposal

CONCEPTUAL DRAFT

Reducing Energy Supply through Electric Demand Response:

A Proposal for ConnectedSolutions 2024-2026

Introduction

In accordance with Least-Cost Procurement Statute and Least-Cost Procurement Standards, Rhode Island Energy respectfully files this proposal for continuation of its demand response program, branded ConnectedSolutions, during 2024-2026. Herein, the Company motivates the value of offering an electric demand response program, describes the conceptual design of ConnectedSolutions, proposes and motivates some program design modifications, offers preliminary annual peak reduction targets and associated budget, and requests approval for cost recovery of the budget via the System Reliability Procurement Factor (SRP Factor) added to the Energy Efficiency System Benefit Charge (EE Charge).

Timeline for Development and Review

September 6	Preliminary draft SRP Investment Proposal circulated for external review and feedback
September 20	Opportunity for discussion of SRP Investment Proposal at the SRP Technical Working Group meeting
September 21	Revised draft SRP Investment Proposal included in final draft of *2024-2026 SRP Three-Year Plan*; opportunity for discussion at the EERMC meeting on September 28
October 18	Opportunity for discussion of SRP Investment Proposal at the SRP Technical Working Group meeting
November 1	SRP Investment Proposal submitted to EERMC for review per LCP Standards 6.3.G

November 15	Opportunity for discussion at the SRP Technical Working Group meeting
November 16	Possible discussion, action at the EERMC meeting
November 21	SRP Investment Proposal included as Appendix to *2024-2026 SRP Three-Year Plan* filed with the Commission
December 15	SRP Investment Proposal filed for regulatory review and approval alongside, but separate from, the *FY25 Electric ISR Plan*

Motivation, Objectives, and Program Design Principles

Electricity supply costs differ in the summer and the winter, driven by economics of generation plants needed to serve the amount of electricity consumed by customers (called 'load') and the fuel costs for those generation plants. On hot, humid summer weekday afternoons and evenings, customers typically demand the most electricity, and this 'peak demand' requires the less and less economically efficient generators to produce electricity to serve the load. These 'peaker plants' are the most expensive generators and drive up summer electricity supply costs.[30]

Rhode Island Energy proposes to offer a 'demand response' program to incentivize participating customers to shift a portion of peak electricity demand to off-peak hours in 2024-2026. This shift (referred to technically as 'reducing regional coincident peak demand') should reduce peak electricity supply costs and, therefore, put downward pressure on wholesale electricity supply prices which may translate to lower supply rates.

The objective of Rhode Island Energy's demand response program, branded ConnectedSolutions, is to reduce regional coincident peak demand.

In offering ConnectedSolutions, the Company asserts the following program design principles, explained further below:

1. Be agnostic toward technology and participants
2. Encourage diffuse and diverse participation for reliable response
3. Right-size incentives
4. Comply with Least-Cost Procurement Standards
5. Reduce and mitigate distribution system issues
6. Share value created

Stemming from the program objective to reduce peak demand, Rhode Island Energy does not differentiate a kilowatt reduced by one technology or participant from a kilowatt reduced by another technology or participant. Each of those kilowatts reduced has the same value for putting

[30] Electricity supply costs reflect three components: energy, capacity, and ancillary. Reducing peak demand puts downward pressure on energy and capacity supply cost components, which benefits all customers.

downward pressure on electricity supply costs. In this manner, ConnectedSolutions is technology and participant agnostic.

This principle is most clearly displayed in commercial and industrial participation in ConnectedSolutions, where participants can use any technology, process, or other innovation to reduce peak demand. For residential and small business participants, technology is limited by practical considerations for implementation (i.e., a subset of thermostat and battery manufacturers and models). Rhode Island Energy seeks to expand eligible technologies in 2024-2026 to include electric vehicles that can automatically curtail charging during peak events.

ConnectedSolutions is a voluntary program; not all participants reduce demand when called on. Rhode Island Energy seeks to build a demand response program with a relatively certain level of response from its participants. This leads to favoring program design that encourages diffuse participation (i.e., no one participant's level of response substantially sways the overall peak demand reduction achieved by the program) and diverse participation (i.e., no one technology type exerts a disproportionate influence on the overall peak demand reduction achieved by the program). This principle is intended to be complementary – not contradictory – to the principle of being technology and participant agnostic. All else equal, more participants and more technologies will result in a more reliable and consistent level of response. Rhode Island Energy seeks to encourage more participants over fewer, with more technology types than fewer, within its program design for ConnectedSolutions.

While each kilowatt of peak demand reduction is considered to be equal, achieving each kilowatt of peak demand reduction may require different levels of action or opportunity cost on the part of the participant. For example, an automatic setback to a participant's thermostat requires no action, while a request for participants to reduce their thermostats manually requires some action. Another example, having a thermostat that is controllable is a relatively small upfront cost and workload when compared to the upfront costs and work entailed to install a battery energy storage system. A third example for good measure, the opportunity cost of setting back a thermostat (potential temporary discomfort) is small relative to the opportunity cost of skipping a production sequence (definite lost revenue). Rhode Island Energy's third program design principle posits that incentives should be right sized to spur action; because different methods of reducing peak load require different burdens, it makes sense to differentiate incentive levels. Doing so will minimize program costs while achieving the same peak demand reduction.

Demand response activities are contemplated within the Least-Cost Procurement Statute, and further stipulated in the Least-Cost Procurement Standards. Accordingly, demand response must be reliable, prudent, cost-effective, and environmentally responsible. These Standards constitute guardrails on program design. One example of application of these guardrails is with limitations on eligible technologies incentivized for reducing peak demand. Switching from electricity to fossil-fuel generators to reduce peak demand is inconsistent with the Standard of environmental responsibility; therefore, fossil-fuel generation is ineligible to receive incentives from ConnectedSolutions.

An eligible alternative to fossil-fuel generation is battery energy storage, which can power a home or business during a peak period and/or export electricity to the electric distribution system for other customers to use. However, large levels or concentrated electricity export may have unintended adverse impacts to the electric distribution system, especially as battery energy storage becomes more common. Rhode Island Energy seeks to maintain the benefits of peak demand reduction through program design that encourages on-site consumption of stored electricity and discourages large levels of unconstrained exported electricity on feeders with relatively low capacity to handle that export.[31]

Rhode Island Energy is creating value by offering ConnectedSolutions. This value is primarily tangible monetary value – customers keep money in their wallets because electricity bills are less expensive because of ConnectedSolutions. Rhode Island Energy seeks to share this quantifiable monetary value between customers and its shareholders such that *all* parties are better off with ConnectedSolutions than without.

Program Design for 2024-2026

This section describes major program design elements of ConnectedSolutions as well as proposed program design modifications for 2024-2026. This section is not intended to be comprehensive of all program design detail; such detail will be developed and made available in advance of each peak demand season, annually.

Administration

<u>Rhode Island Energy's Role</u>:
Rhode Island Energy serves as the Program Administrator, providing strategic direction and management of ConnectedSolutions. Rhode Island Energy's role manifests through program design, implementation, and evaluation. Rhode Island Energy is uniquely suited for this role because of its expertise in wholesale energy and capacity markets, knowledge of its electric distribution system to mitigate risks through program design, everyday relationship with its customers to promote program participation, and ability to coordinate demand response with all other business activities.

<u>Implementation Vendor</u>:
Rhode Island Energy contracts with a third-party solution provider that offers software-as-a-service to implement day-to-day program operations. This implementation vendor is responsible for managing relationships and contracts with technology providers, in order to enable those technologies to participate in ConnectedSolutions (or, more precisely, to enable customers who

[31] Although interconnection system impact studies do examine the stated charge/discharge patterns of battery energy storage systems, including reducing or mitigating system issues as a program design principle is a necessary and beneficial backstop to ensure demand reduction benefits. In this manner, consistency in considering distribution system issues in demand response program design carries over to system impact studies to ensure full flexibility in program participation without adverse system risks.

have those particular technology types and models to enroll and participate). The implementation vendor also assists with data collection, participant enrollment, program impact evaluation, participant satisfaction, troubleshooting, incentive payouts, and ancillary technical assistance. Contracting with a vendor for these roles allows Rhode Island Energy and its customers to benefit from the innovation and price competition within the competitive market for demand response implementation.

Prior to peak season in 2024, Rhode Island Energy will conduct a competitive solicitation for an implementation vendor, in accordance with the system reliability procurement process described in the *2024-2026 SRP Three-Year Plan*. The intent is for a vendor to be tentatively selected prior to filing this SRP Investment Proposal, with final contract and scope of work contingent on regulatory ruling.

Curtailment Service Providers:
Rhode Island Energy and its implementation vendor work with a network of curtailment service providers. These curtailment service providers manage relationships with commercial and industrial customers under their own, independent contracts for value-sharing to which Rhode Island Energy is not party. However, curtailment service providers are essential to the ecosystem of ConnectedSolutions so that they align their support for commercial and industrial customers with Rhode Island Energy's calls for peak demand reduction.

Administrative Vendors:
Rhode Island Energy contracts with additional vendors to support administrative functions, including but not limited to, administering financing interest buy-down incentives.

ConnectedSolutions

ConnectedSolutions is designed for participation by all customers. Reducing peak demand through setting back thermostats, discharging battery energy storage systems, curtailing electric vehicle charging, or voluntarily are all ways in which residential and business customers can participate. For commercial and industrial customers, specially designed Daily Dispatch and Targeted Dispatch programs offer more flexible avenues of participation that accommodate more complex technologies (e.g., building automation systems, complex lighting controls, etc.) and processes (e.g., deferring production) participants can leverage to reduce peak demand.
The following subsections describe the conceptual design, and in some cases, proposed changes to program design for each avenue of participation.

Smart Thermostats

Residential and small business customers may enroll eligible smart thermostats in ConnectedSolutions. During peak periods, smart thermostats will automatically increase target cooling levels, thereby reducing demand of central air conditioning units. Eligibility is defined by thermostat manufacturers and model, as determined by the implementation vendor.

Incentive structure and amount:
Eligible participants receive a one-time enrollment incentive of $50 per enrolled device followed by an annual participation incentive of $25 per device per year, to be rendered at the end of the peak season for all participants with full participation in at least 50 percent of peak events.

Changes from prior program design:
Rhode Island Energy is proposing to change the amount of the one-time enrollment incentive. Under prior program design, participants received $25 upfront for enrollment. Rhode Island Energy is proposing to increase this one-time enrollment incentive to $50. Rhode Island Energy bases this proposed program design modification on the theory of change that federal funding and state programs will encourage additional adoption of energy efficient cooling systems, and the adopters of these technologies are likely further along in the technology adoption spectrum. Therefore, Rhode Island Energy generally proposes increases this upfront incentive to encourage a larger portion of energy efficient cooling system adopters to simultaneously participate in demand response.

Battery Energy Storage Dispatch
During peak periods, battery energy storage systems discharge electricity to serve on-site load and export electricity to the electric distribution system for neighboring customers to use, thereby reducing peak demand.

Incentive structure and amount:
Eligible participants receive an annual performance incentive of $TK per average peak kilowatt reduced per peak event per year, to be rendered at the end of the peak season for all participants. Some eligible participants may additionally opt to leverage the HEAT Loan to support financing their battery energy storage systems. The HEAT Loan provides low-interest rate financing, with zero-percent interest financing available to some customers based on income eligibility.

Changes from prior program design:
In accordance with the program design principle to right-size incentive levels, Rhode Island Energy is proposing to change the amount of the performance incentive. Under prior program design, participants received $400 per average kilowatt reduced per peak evet per year. Recent changes to incentive levels in neighboring states suggest that participants are willing to reduce peak demand for less incentive; therefore, Rhode Island Energy seeks to reduce the performance incentive to better align with revealed participant willingness to accept. Modifying the performance incentive has the additional benefit of allowing more participants for the same program cost, which advances the program design principle to encourage diffuse and diverse participation for reliable response.

Electric Vehicle Charging Curtailment
New for 2024-2025, Rhode Island Energy proposes to incentivize participants who drive electric vehicles to curtail charging during peak demand periods.

Incentive structure and amount:
Eligible participants receive a one-time upfront incentive of $TK per enrolled vehicle followed by an annual performance incentive of $TK per average peak kilowatt reduced per peak event per year, to be rendered at the end of the peak season for all participants.

Notes about program design:
Rhode Island Energy will propose an off-peak charging rebate program to begin in 2024. The electric vehicle charging curtailment option through ConnectedSolutions is distinct and separate from the to-be-proposed off-peak charging rebate program in the following ways:

- Customers may only participate in one program or the other; customers may not participate in *both* the off-peak charging rebate program *and* electric vehicle charging curtailment through ConnectedSolutions.
- The off-peak charging rebate program structures its incentive as a dollar value per *kilowatt-hour* reduced *cumulatively* during peak periods; the incentive for electric vehicle charging curtailment through ConnectedSolutions is structured as a dollar value per *kilowatt* reduced *on average* during peak periods.
- The off-peak charging rebate program requires an action by the participant to participate in each peak period; the electric vehicle charging curtailment option through ConnectedSolutions does not require any action by the participant to participate in peak events.

By offering both the off-peak charging rebate program and the electric vehicle charging curtailment option through ConnectedSolutions, Rhode Island Energy seeks to learn about the differential impacts and customer acceptance of these programs to reduce peak demand. Such learnings may inform future program and rate designs.

Voluntary
Rhode Island Energy proposes a new communications strategy to encourage voluntary peak reduction through any means or technology by any customer in response to peak events.
Incentive structure and amount:
Voluntary demand response will not provide any direct monetary incentive to participants for peak demand reduction, although all customers will benefit through downward pressure on electricity supply costs.

Notes about program design:
Rhode Island Energy will primarily leverage its in-house communications team and communications channels (specifically: social media and customer text messages and/or emails) for its voluntary demand response.

Daily Dispatch
Commercial and industrial customers may enroll in ConnectedSolutions Daily Dispatch. Daily Dispatch incentivizes customers on a pay-for-performance basis to curtail their electricity demand during the one peak grid load hour of the year, as well as other high and medium peak days in June through September, for a total of no more than 60 events.

Incentive structure and amount:
Customers earn a performance incentive of $300 per kilowatt reduced on average during peak events.

Targeted Dispatch
Commercial and industrial customers may enroll in ConnectedSolutions Targeted Dispatch. Targeted Dispatch incentivizes customers on a pay-for-performance basis to curtail their electricity demand during the one peak load hour of the year and other high peak days in June through September, for a total of no more than eight events.

Incentive structure and amount:
Customers earn a performance incentive of $40 per kilowatt reduced on average during peak events. Customers earn a performance incentive of $40 per kilowatt reduced on average during peak events.

Modification in Program Design:

Rhode Island Energy is proposing modifications in program design specifically for battery energy storage systems larger than 25 kW. Three program design principles motivate these program design modifications: (i) encourage diffuse and diverse participation for reliable response, (ii) comply with Least-Cost Procurement Standards, and (iii) reduce and mitigate distribution system issues.

Rhode Island Energy motivates this modification in program design through an illustration of potential behavior and adverse consequences allowable under prior program design: a single large battery energy storage system (e.g., 5 MW) sited at an industrial facility with smaller peak demand (e.g., 2 MW). Consider a 70 MW peak demand reduction target. This battery potentially constitutes 7% of peak demand reduction – whether the battery participates or not could result in a variation of 5 MW peak reduction, or 7% of peak demand reduction achieved. That 7% proportion of peak reduction is determined by a single participant-technology threatens the reliability of expected response. If this battery participates at a performance incentive rate of $400 per average kilowatt reduced per peak event, then the battery would earn an incentive of $2 million, TK% of the program budget. That TK% of program budget could be awarded to a single participant is inconsistent with the Least-Cost Procurement Standard of prudency, specifically: "how the investment is equitable in consideration of the allocation of costs, the allocation of benefits, customer access, and customer participation" (Standards 1.3.E.i.e). Finally, the call to respond during a peak event, and resulting export, may create unforeseen distribution system issues,[32] such as overloads on a feeder segment, as well as potentially suboptimal use of hosting and loading capacity on that feeder. Rhode Island Energy seeks to strike the right balance between creating value through system peak demand reduction and mitigating potential distribution system Issues that may erode that value.

In light of these program design principles, Rhode Island Energy seeks to implement two program modifications: (i) imposing a cap on incentive payout for any single customer and (ii) encouraging battery deployment specifically on feeders with higher capacity. The specific details of these proposed program modifications (i.e., the method of determining the incentive cap, the structure to differentially encourage deployment, and the method for determining level of encouragement) are open to discussion and input. With the objective of encouraging broad participation by customers, Rhode Island Energy will provide preference to recommendations for simple and easy-to-understand program design modifications. Rhode Island Energy seeks stakeholder recommendations on ways in which program designers could, should, or should *not* modify program design to achieve program design principles. All comments, questions, and recommendations should be emailed to Carrie Gill at cagill@rienergy.com.

Annual Peak Reduction Targets
[Forthcoming]

Budget, Performance Incentive, and Funding Source
[Forthcoming]

Request for Ruling
[Forthcoming]

[32] If not studied in interconnection system impact studies and mitigated via system modifications or improvements.

Gas Demand Response Pilot

System Reliability Procurement Investment Proposal

Reducing Gas System Peak Demand through Gas Demand Response:

A Proposal for the Gas Demand Response Pilot 2024-2026

Introduction

In accordance with Least-Cost Procurement Statute and Least-Cost Procurement Standards, Rhode Island Energy respectfully files this proposal for continuation of its Gas Demand Response Pilot during the period 2024-2026. Herein, the Company motivates the conceptual value of offering a demand response program, describes the general concepts of Gas Demand Response Pilot (or 'Gas DR Pilot'), proposes a potential program design expansion, offers an hourly peak reduction target and associated budget, and requests approval for cost recovery of the budget via the System Reliability Procurement Factor added to the Energy Efficiency System Benefit Charge.

Timeline for Development and Review

September 6	Preliminary draft circulated for external review and feedback
September 20	Opportunity for discussion at the SRP Technical Working Group meeting
September 20	Draft of SRP Investment Proposal submitted to Energy Efficiency and Resource Management Council for review per LCP Standards 6.3.G
September 21	Revised draft included in final draft of *2024-2026 SRP Three-Year Plan*; opportunity for discussion at the EERMC meeting
October 11	Revised draft of SRP Investment Proposal submitted to Energy Efficiency and Resource Management Council for review
October 18	Opportunity for discussion at the SRP Technical Working Group meeting
October 19	Possible discussion, action at the Energy Efficiency and Resource Management Council
November 17	SRP Investment Proposal filed for regulatory review separate from the *FY25 Gas ISR Plan*
November 17	SRP Investment Proposal included as Appendix to 2024-2026 SRP Three-Year Plan filed with the Commission

Motivation, Objectives, and Program Design Principles

Rhode Island Energy is a public utility under the provisions of R.I. Gen. Laws § 39-1-2 and provides natural gas sales and transportation service to approximately 270,000 residential and commercial customers in 33 cities and towns in Rhode Island. Each year, the Company must ensure it maintains sufficient gas supply in its resource portfolio to continuously supply the amount of gas required by customers' (called 'demand' or 'load') throughout the year under all reasonable weather conditions.

Ensuring there is adequate supply to meet customer requirements is particularly important on the coldest days during the winter period when customer demand is at its highest (called 'peak demand'), as the inability to provide gas to customers for heating could create unsafe environments. To accomplish this, the Company must maintain sufficient supply under contract and in storage (underground storage and LNG), reduce peak demand, and/or have sufficient time to contract for additional resources should they be required. Even so, during the coldest days of the year when our system is near daily or hourly peak demand, upstream or on-system constraints may result in demand exceeding available pipeline capacity in certain areas on the system.

Rhode Island Energy proposes to continue to offer the Gas Demand Pilot to test (1) the level of customer interest and scalability of the program, and (2) the gas system benefits of incentivizing the reduction or curtailment of gas usage during system peak demand periods (from November 1st to March 31st) when requested, provided doing so does not compromise safety. The Gas DR Pilot offerings will continue to target large commercial and industrial customers with firm service – that is, a minimal amount of continuous, uninterruptible gas demand which the Company is obligated to serve. The Gas DR Pilot may also test the interest of residential and small-business customers with eligible smart thermostats who are already enrolled in the Company's ConnectedSolutions electric demand response program and the system benefits associated with their participation.

Learnings for the pilot program will focus on how to increase program enrollment and participation during peak demand events, as well as scalability of the program within and beyond large commercial and industrial customers. Aquidneck Island will continue to be a particular focus, but other areas with similar capacity constraints will be evaluated. Rhode Island Energy will report the resulting impacts of its demand response program in its SRP Annual Reports.

The objective of Rhode Island Energy's Gas Demand Response Pilot is to test customer adoption and the effectiveness of gas demand response in reducing system peak demand.

As noted above, during the coldest days of the year, forecasted peak demand may exceed pipeline capacity, resulting in capacity-constrained areas on the system. Reducing peak demand through demand response has the potential to mitigate capacity constraints on the system.

In offering the Gas Demand Response Pilot, the Company asserts the following program design principles, explained further below:

1. Technology and participant agnostic
2. Encourage diffuse and diverse participation for reliable response
3. Right-size incentives
4. Compliant with Least-Cost Procurement Standards
5. Reduce and mitigate distribution system risk
6. Share value created

Stemming from the program objective to reduce peak demand, Rhode Island Energy does not differentiate dekatherms (Dth) reduced by one technology or participant from Dth reduced by another technology or participant. Each of those Dth reduced has the same benefit with respect to reducing peak demand and avoiding or alleviating capacity constraints on the system. In this manner, the Gas DR Pilot is technology and participant agnostic.

This principle is clearly displayed in commercial and industrial participation in the Gas DR Pilot, where participants can use any technology, process, or other innovation to reduce peak demand – this has historically been accomplished either by temporarily switching to an alternative, back-up heating source or through adjusting thermostat settings (called 'thermostat setback'). For residential and small business participants, technology eligibility is anticipated to be limited to smart thermostats that can be automatically setback during peak demand events. It was originally contemplated that residential and small business customers with hybrid gas-electric heating systems could temporarily curtail gas use and switch to electric heating to reduce peak demand. After consideration, however, it was determined the cost of relying on all-electric heating during the coldest days of the year – the opposite of how a hybrid electric-gas heating system is designed to perform – is likely to be greater than the incentive a customer would receive for participating in a peak demand event.

Consistent with its electric demand response program, Rhode Island Energy seeks to build a gas demand response program with a reliable level of response from its participants. This leads to favoring program design that encourages diffuse participation (i.e., no one participant's level of response substantially sways the overall peak demand reduction achieved by the program) and diverse participation (i.e., no one technology type exerts a disproportionate influence on the overall peak demand reduction achieved by the program). This principle is intended to be complementary – not contradictory – to the principle of being technology- and participant-agnostic. All else equal, more participants and more technologies will result in a more reliable and consistent level of response. Rhode Island Energy seeks to encourage more participants over fewer, with more technology types than fewer, within its program design for the Gas Demand Pilot.

While each Dth of peak demand reduction is considered to be equal, achieving each Dth of peak demand reduction may require different levels of action or opportunity cost on the part of the participant. For example, an automatic setback to a participant's thermostat or switch to a back-up source of heating requires no action, while a request for participants to manually adjust their thermostats or switch to a backup heating system requires some action. Another example, having a controllable thermostat for purposes of changing the setpoint only is a relatively small upfront cost and workload when compared to the upfront costs and work required to install a new primary or secondary heating system. A third example for good measure, the opportunity cost of setting back a thermostat (below a customer's preferred temperature) is small relative to the opportunity cost of deferring a production sequence (definite lost revenue) or potential increased cost of temporarily running a back-up heating system. Rhode Island Energy's third program design principle posits that incentives should be right sized to spur action so, because different methods of reducing peak demand require different burdens, it makes sense to differentiate incentive levels. Doing so will minimize program costs while achieving the same peak demand reduction.

Demand response activities are contemplated within the Least-Cost Procurement Statute, and further stipulated in the Least-Cost Procurement Standards. Accordingly, demand response must be reliable, prudent, cost-effective, and environmentally responsible. These Standards constitute guardrails on program design. As an example, the electric demand response program, switching from electricity to fossil-fuel generators to reduce peak demand is inconsistent with the Standard of environmentally responsible; therefore, fossil-fuel generation is an ineligible technology for the electric demand response program. However, for the Gas DR Pilot, most large commercial and industrial customers currently cannot meet their space, process, or production heating needs without use of fossil fuels, so switching from gas to another combustible fuel is not inconsistent with the environmentally responsible guardrail.

Rhode Island Energy's Gas DR Pilot is designed to create value. The primary value – to the company and program participants – is risk mitigation. Participating customers receive incentive payments for reducing demand during peak events, thus potentially reducing the need for on-system investments to mitigate capacity constraints. Rhode Island Energy seeks to share this quantifiable value between customers and its shareholders such that *all* parties are better off with the Gas DR Pilot than without.

Program Design for 2024-2026

This section describes major program design elements and goals of the Gas DR Pilot as well as a potential program design modification for 2024-2026.

Continuation of C&I Customer Offerings – Hourly Peak Reduction Targets and Program Design
The Company will continue to target 40-50 Dth of hourly peak reduction during the winter months (Nov. 1st through March 31st) of 2024-2026 through two individual large commercial and industrial customer DR offerings. The Company expects that the majority of these peak

reduction savings will come from customers participating in what is called the full day Extended Demand Response (EDR) pilot offering, with the remainder from customers participating in a Peak Period Gas Demand Response (PPDR) pilot offering. These demand reduction pilot offerings are described in more detail below. The hourly Dth reduction target will be dependent on enrollment levels and establishing a sufficient incentive level to drive effective participation. The hourly peak reduction target and associated budget may be adjusted annually for subsequent winter months (November 1st through March 31st) during the remainder of the 3-year plan (2024-2026).

During the winter of 2018/19, the Company launched the PPDR pilot offering, which incentivizes customers to shift their usage outside of the peak-period of the gas system (6AM-9AM from November 1st to March 31st). This pilot targets large commercial and industrial customers who have intra-day flexibility of their natural gas usage. Customers participating in this pilot are able to achieve demand reduction via non-gas backup heating or thermostat setback.

In 2019/20, the company added the EDR offering, which targets large commercial and industrial customers that can achieve 24-hour gas reductions (10AM on day 1 until 10AM on day 2, Nov. 1st through March 31st), primarily with non-gas back-up heating.

For both DR offerings, Rhode Island Energy may place a limit on the number of consecutive days on which any individual customer can be called participate during the winter, but the Company will have the right to call up to 6 events during the winter at the established incentive rate. Customer participation in the peak demand events will be compensated via direct incentive payments, not in the form of a reduced rate. Going into the 2024-2026 winter season, the company will maintain both the PPDR and EDR offerings.

Measurement of demand reduction for the PPDR and EDR program offerings will continue to require the installation of data recording hardware that provides granular usage data for participating customers. Additional data recording hardware requirements will be determined if the program is expanded beyond large commercial and industrial customers. The data collected will be directly used to inform the pilot research questions identified in the next section, "Pilot Program Goals". Data from the Gas DR pilot will be evaluated each year.

Pilot Program Goals

Gas demand response is a pilot program. We are trying to understand the scalability of the program and the degree to which it might offset a utility reliability procurement. However, gas demand response hasn't provided the level of relief anticipated due to lack of performance during called events and low customer interest, so enhancements may be needed to create a more effective program. Continuing to test the efficacy of gas demand response will allow Rhode Island Energy to understand gas demand response's impact on gas system needs and optimization, customer interest, effectiveness of incentive levels, and scalability of the program, as well as its potential applicability to other customer classes. Specifically, the goal of the Gas

DR Pilot is to leverage following research questions in ascertaining how to increase program enrollment and participation during peak demand events:

- Are large commercial and industrial customers interested in participating in an incentivized gas demand response program?
- Are residential customers with eligible smart thermostats interested in participating in gas demand response?
- What incentive structure and level are sufficient to stimulate program enrollment and participation?
- How do we increase enrollment – within and possibly across customer classes – and scale the program? Can program enrollment be increased through targeted marketing and/or the use of aggregators?
- What are distribution system benefits of gas demand response? From large commercial and industrial customer participation? For residential customer participation, if the pilot is expanded?
- Is there a minimum threshold for participation to realize system benefits? Does this differ across customer classes?

In 2024, Rhode Island Energy will initiate testing the effectiveness of leveraging target marketing and aggregators to increase enrollment and participation of large commercial and industrial customers. Depending on the outcome from the use of target marketing and aggregators, in 2025 the Company may adjust the incentive for large commercial and industrial customers to test the impact on enrollment and participation. Also in 2025, Rhode Island Energy anticipates testing residential customers' interest in a gas demand response offering and the associated benefits of participation in such a program expansion on the gas system during peak events.

Program Administration
Rhode Island Energy will serve as the Program Administrator for the Gas DR Pilot. In this role, Rhode Island Energy will provide strategic direction and management of the Gas DR Pilot. The Company's role manifests through program design, implementation, and evaluation. Rhode Island Energy is uniquely suited for this role because of its management of gas supply procurement, knowledge of its gas distribution system to mitigate risks through program design, everyday relationship with its customers to promote program participation, and ability to coordinate with all other business activities.

Rhode Island Energy will be responsible for day-to-day program operations and managing relationships and contracts with customers enrolled and participating in the Gas DR Pilot. The Company will also be responsible for data collection, participant enrollment, program impact evaluation, participant satisfaction, participant troubleshooting, incentive payouts, and ancillary technical assistance.

Because the gas demand response program is in the pilot stage and designed to test the benefits of reducing gas system peak demand, customer adoption of gas demand response, the incentive levels required drive participation, and RI Energy's role in influencing market adoption, it is, by nature of its design and goals, necessary for the Company to administer the program. Should the Gas DR Pilot be successful in increasing enrollment and participation – particularly if the program is successfully expanded to include residential and small business customers – to the degree it is no longer practical for Rhode Island Energy to manage administration of the program, the Company may propose to contract with a third-party administrator. Any incremental costs associated with services provided by a third-party administrator will be proposed via an amendment to this Gas DR Pilot SRP Investment Proposal. Following the Gas DR Pilot, Rhode Island Energy will evaluate whether there is value in launching a full-scale demand response program, which may also contemplate the use of a third-party program administrator.

Large Commercial & Industrial Customers
Target Participants:

The Gas DR Pilot is specifically designed for large commercial and industrial customers with firm service.

Eligible Technologies – HVAC Controls and Back-Up Heating Systems:

Customers participating in the Gas DR Pilot must be able to provide peak demand reduction via HVAC setbacks or by switching to a back-up heating system that utilizes a fuel other than natural gas.

Incentive Structure and Amount:

As was the case in prior years, customer compensation for participation in the Gas DR Pilot offering will be based on a combination of 'reservation' and 'energy' payments that differ for the PPDR and EDR offerings. Each of these rates will be standard offers to all customers, though customer earning opportunity will vary based on the volume of peak hour Dth reduction that each customer can commit to and deliver. The Company will utilize a rolling performance rating that measures customer reliability and limits payments to nonperforming resources.

	PPDR	EDR
Event Duration (hours) (Maximum 6/winter)	3 6AM-9AM	24 10AM-10AM
Capacity Payment (per month)	$250/peak-hour Dth	$700/peak-hour Dth
Energy Payment	$50/Dth	$7/Dth

Potential Program Design Modification – Inclusion of Small-Business & Residential Customers

Target Participants:

Rhode Island Energy is proposing to explore a possible expansion of the Gas DR Pilot to residential and small-business customers with eligible smart thermostats who are already enrolled in the Company's ConnectedSolutions electric demand response program. If pursued, it is anticipated this program expansion will take place in 2025 and be motivated and informed by learnings captured from the large commercial and industrial gas demand response offerings.

Eligible Technologies – Smart Thermostats:

If the Gas DR Pilot is expanded, residential and small business customers may enroll eligible smart thermostats. During peak periods, smart thermostats will automatically decrease target heating levels, thereby reducing demand of gas during peak periods. Eligibility will be defined by thermostat manufacturers and model.

Incentive Structure and Amount:

Similar to the ConnectedSolutions electric demand response offering, Rhode Island Energy is contemplating a one-time enrollment incentive per enrolled customer followed by an annual participation incentive per device per year, to be rendered at the end of the peak season for all participants with full participation in at least 50% percent of peak events. The actual incentive levels will be developed and proposed as an amendment to this Gas DR Pilot SRP Investment Proposal prior to the 2025 peak heating season (January 1 through March 31), and will be dependent on anticipated enrollment, participation levels, and system benefits. It is expected the one-time enrollment and annual participation incentives will be similar in quantum as the ConnectedSolutions electric demand response offering: e.g., $50 per enrolled customer and $25 per device per year, respectively.

Annual Peak Reduction Targets

The anticipated annual peak reduction target for the large commercial and industrial customer Gas DR Pilot is expected to continue to be 27,520 therms for the 2024-2026 period. An increase in participation by large commercial and industrial customers, and/or a successful expansion of the Gas DR Pilot to residential and small business customers, may result in additional incremental savings. Incremental reduction targets will be dependent on enrollment and participation levels. Estimated incremental savings associated with increased participation among large commercial and industrial customers at any juncture during 2024-2026, and/or possible new participation of residential and small business customers in 2025, will be developed and proposed in an amended Gas DR Pilot SRP Investment Proposal.

Budget and Funding Source

The anticipated annual budget for the large commercial and industrial customer Gas DR Pilot is expected to continue to be $268,042 for the 2024-2026 period. An increase in participation by large commercial and industrial customers, and/or a successful expansion of the Gas DR Pilot to residential and small business customers, may result in incremental spend associated with incentive payments, administrative, and marketing costs. Funding will be through cost recovery of the budget via the System Reliability Procurement Factor added to the Energy Efficiency System Benefit Charge. Estimated costs associated with increased participation among large commercial and industrial customers at any juncture during 2024-2026, and/or possible new participation of residential and small business customers in 2025, will be developed and proposed in an amended Gas DR Pilot SRP Investment Proposal.

Request for Ruling

Rhode Island Energy will request regulatory approval for its gas demand response pilot program via a *System Reliability Procurement Investment Proposal* to be filed on November 17, separate from the *Gas Infrastructure, Safety, and Reliability ("ISR") Plan* to be filed in December. The *SRP Investment Proposal* will include program design specifications, budget, and anticipated participation and impacts.

Appendix 5. System Data Portal

See attachment.

Rhode Island Energy™
a PPL company

Rhode Island Energy's (RIE)
Rhode Island System Data Portal

USER GUIDE

RIE’s Rhode Island System Data Portal

Rhode Island Energy™
a PPL company

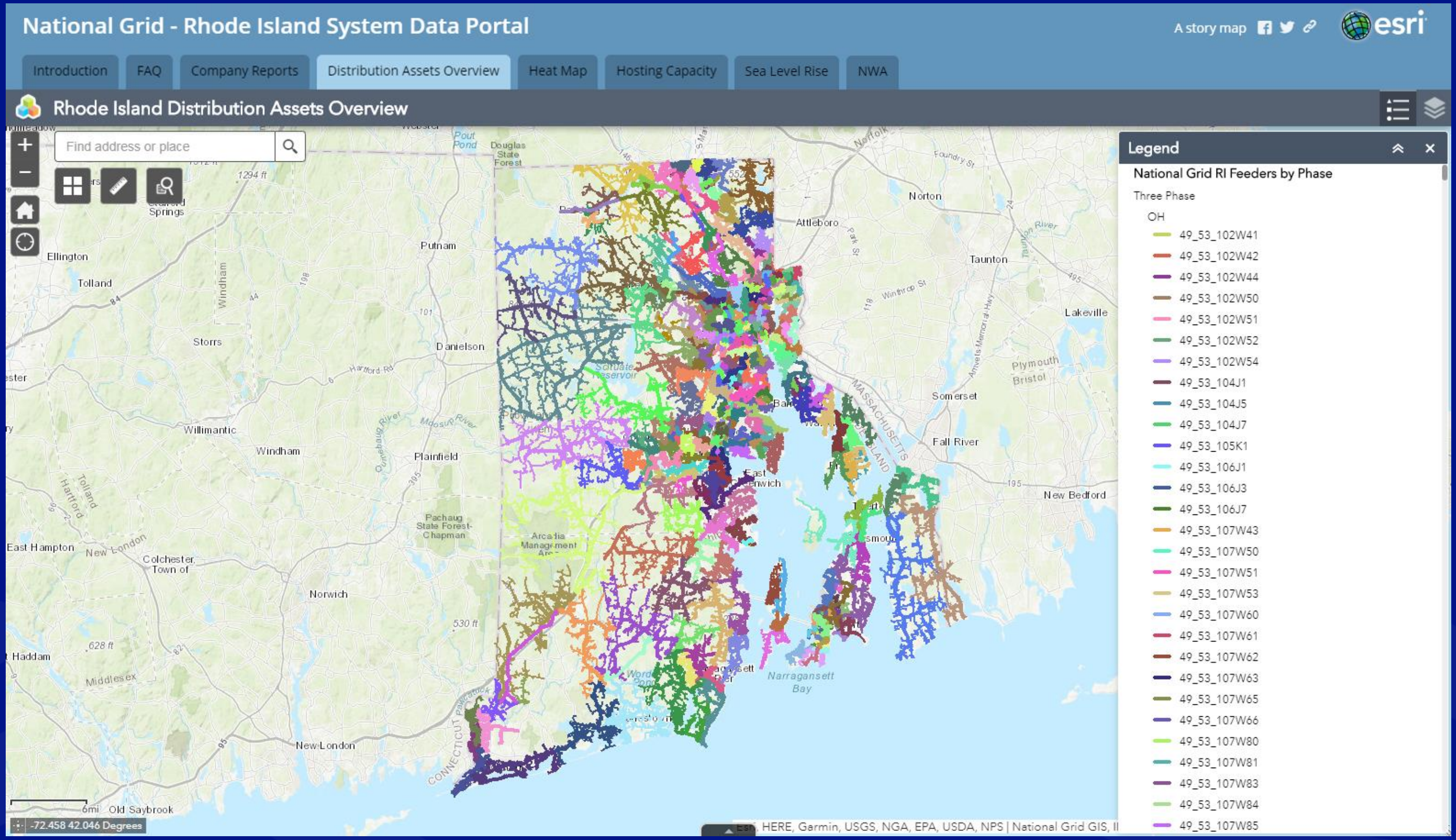


Table of Contents

Rhode Island Energy™
a PPL company

Overview

Rhode Island Energy (RIE) has created a collection of interactive maps to help customers, contractors, and developers identify potential project sites and development opportunities.

The maps provide the location and specific information for selected electric distribution lines and associated substations and assets within the RIE electric service area of Rhode Island.

RIE's electric system is dynamic. System configurations can change for a variety of reasons both planned and unplanned. RIE will update the contents on a periodic basis so please be aware that the same location may show different information over time.

Please note that the Portal and maps are not a guarantee that generators can interconnect at any particular time and place. A number of factors drive the ability and cost of interconnecting distributed generation to the electric system and actual interconnection requirements and costs will be determined following detailed studies. These studies will consider your specific project location, operating characteristics and timing. Additionally, environmental and other required permits are independent of our interconnection process and may limit the suitability of a particular site.

Link to the Rhode Island System Data Portal

Rhode Island Energy™
a PPL company

You can access the Rhode Island System Data Portal

through the RIE customer webpage here:

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

Rhode Island Energy™
a PPL company

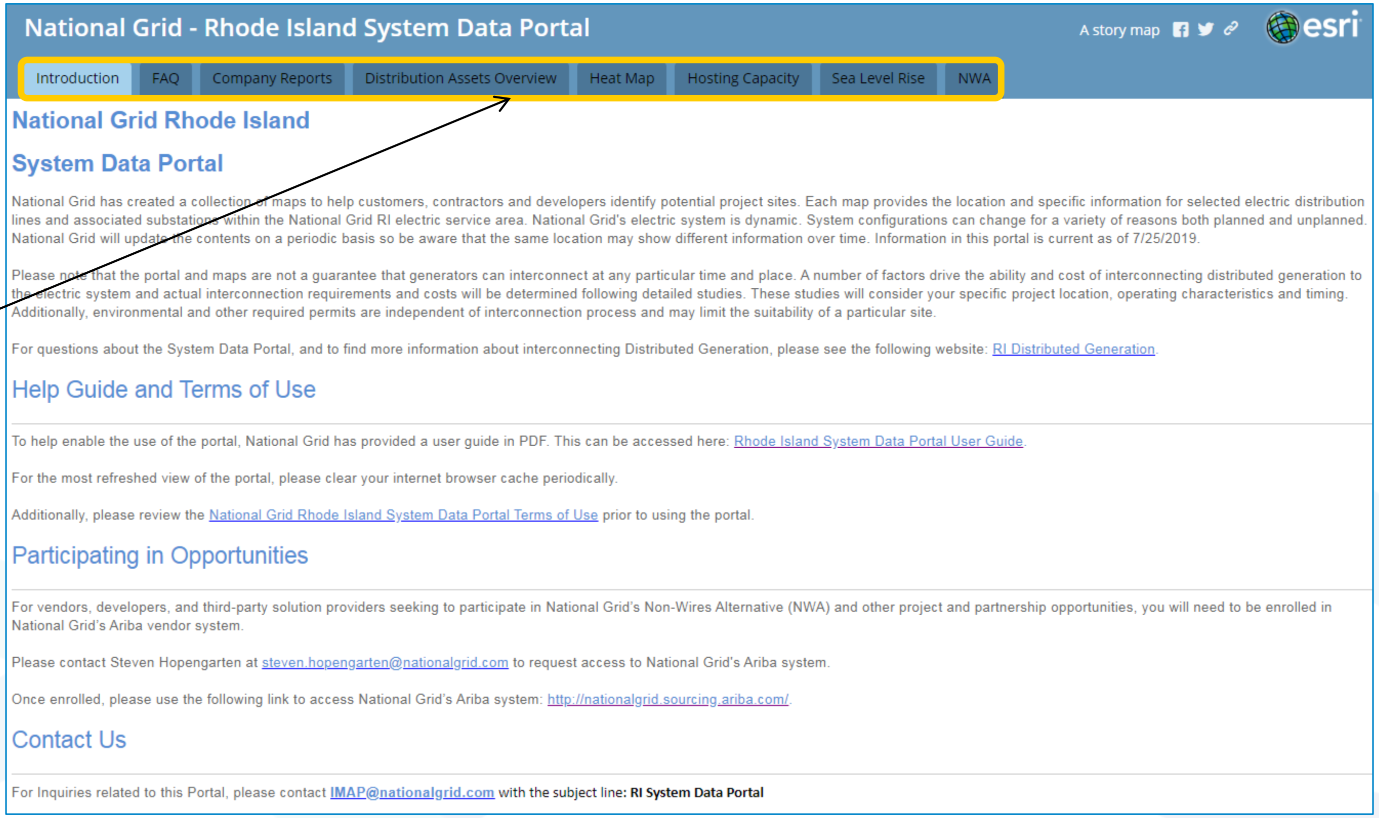
NAVIGATION

Navigation - Tabs

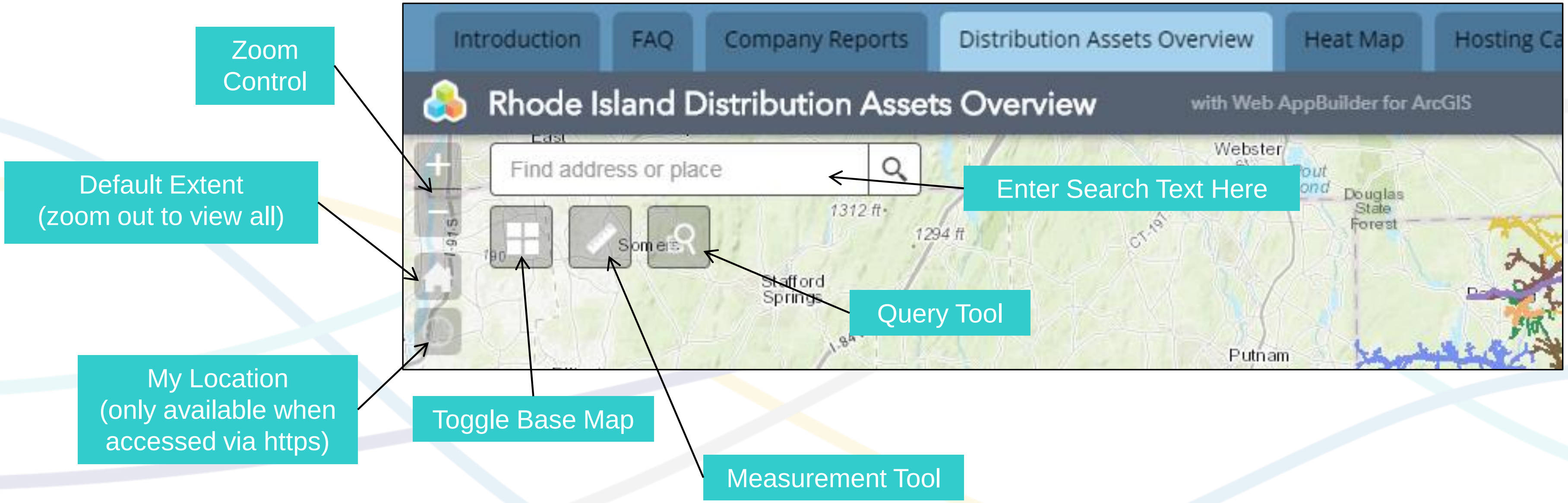
Rhode Island Energy™
a PPL company

The Rhode Island System Data Portal contains tabs for easy navigation.

Select the tabs to navigate between different parts of the Portal



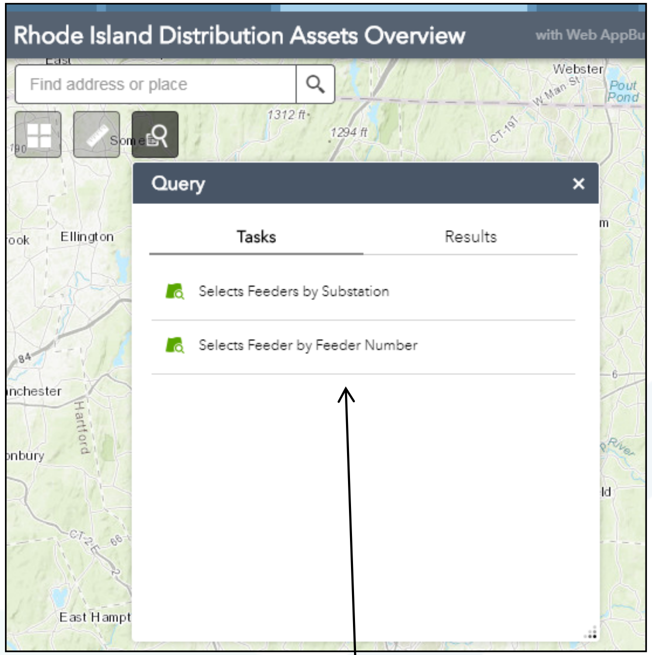
Navigation – Map Search



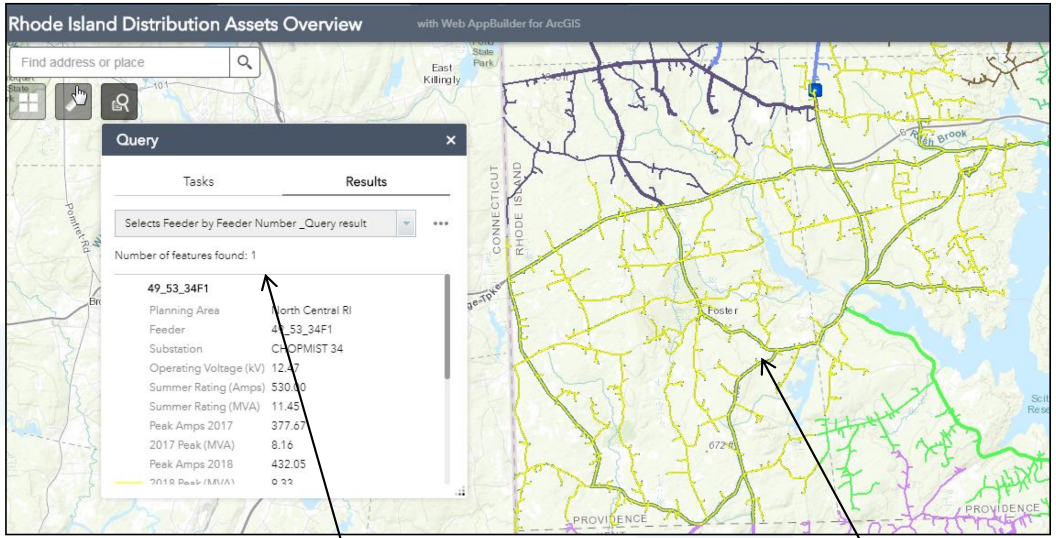
- Use the Search Text bar to find an address or place, similiar to Google Maps.
- Or use the Zoom Controls or mouse wheel to locate a specific location, feeder or substation.

Navigation – Query Tool

Rhode Island Energy™
a PPL company



Select Feeders by Substation Name or by Feeder Number

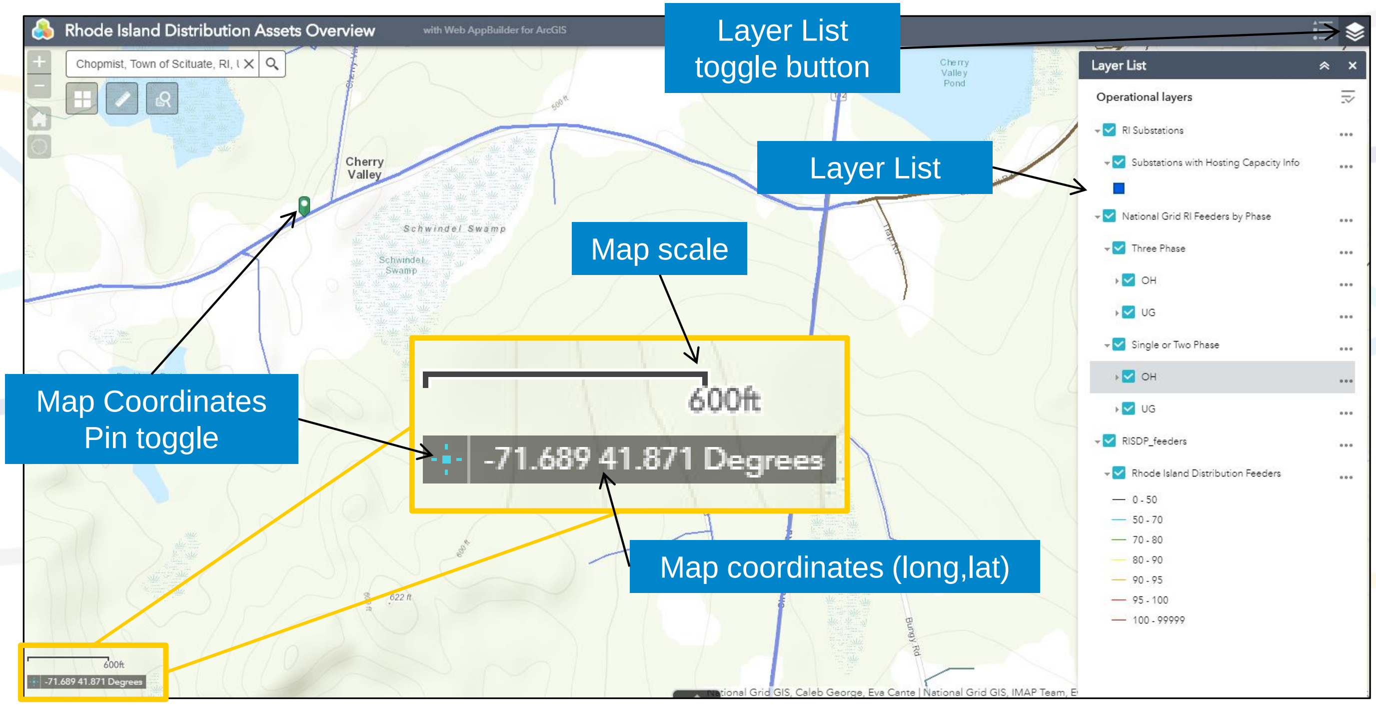


Using the Feeder Number search method, searching for a specific feeder (i.e. 34F1) zooms map to Feeder Location.
Feeder information is displayed below the query.

The feeder is highlighted yellow by this method.

Navigation – Map Coordinates and Layer List

- Each map contains map scale and coordinate data.
- A Layer List can be toggled to show different assets of the map system.



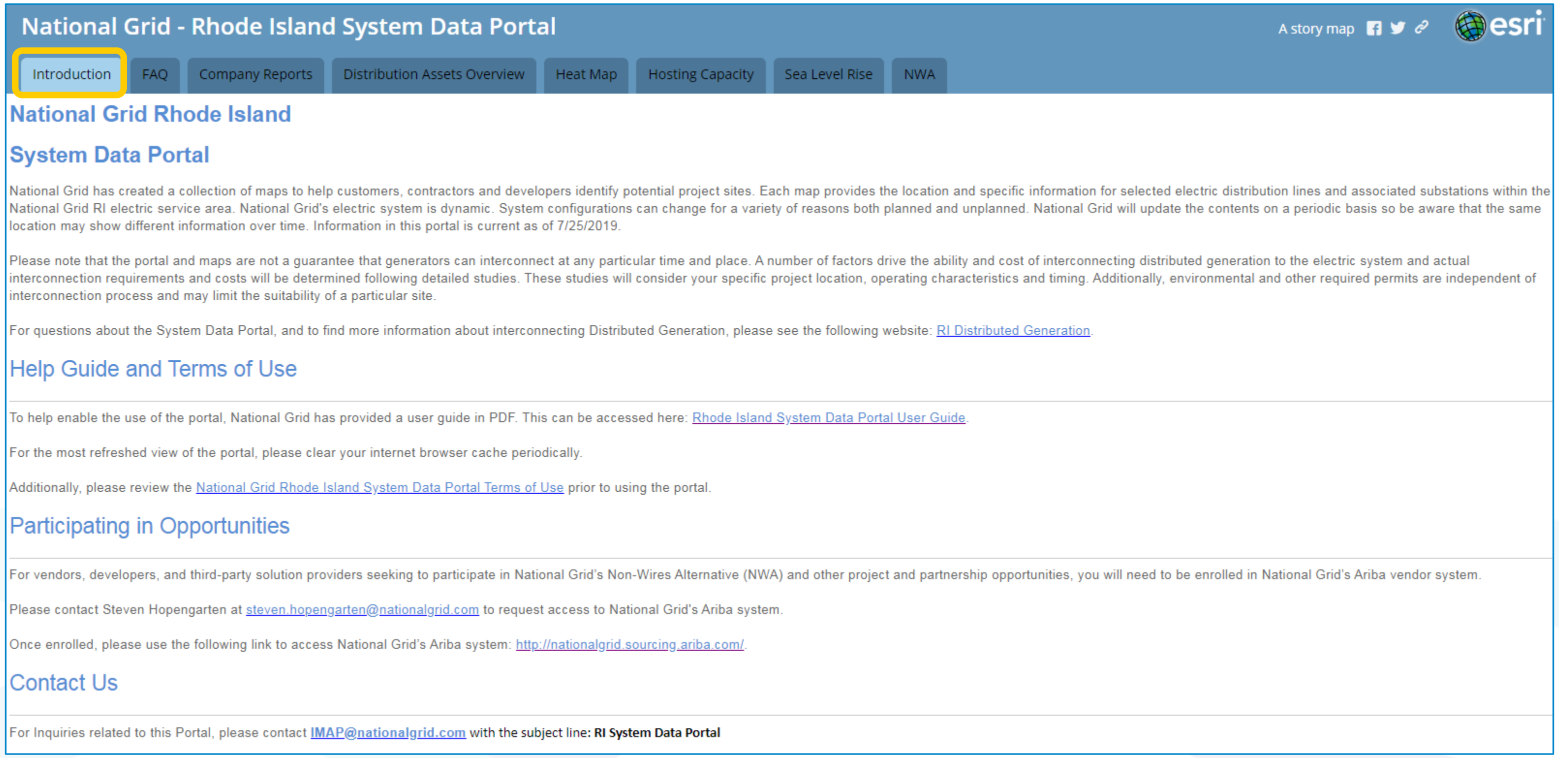
Rhode Island Energy™
a PPL company

TABS & MAP RESOURCES

Tab - Introduction

Rhode Island Energy™
a PPL company

Provides an overview of the Portal, with Contact info and a link to this Help Guide.



National Grid - Rhode Island System Data Portal

A story map

esri

Introduction | FAQ | Company Reports | Distribution Assets Overview | Heat Map | Hosting Capacity | Sea Level Rise | NWA

National Grid Rhode Island

System Data Portal

National Grid has created a collection of maps to help customers, contractors and developers identify potential project sites. Each map provides the location and specific information for selected electric distribution lines and associated substations within the National Grid RI electric service area. National Grid's electric system is dynamic. System configurations can change for a variety of reasons both planned and unplanned. National Grid will update the contents on a periodic basis so be aware that the same location may show different information over time. Information in this portal is current as of 7/25/2019.

Please note that the portal and maps are not a guarantee that generators can interconnect at any particular time and place. A number of factors drive the ability and cost of interconnecting distributed generation to the electric system and actual interconnection requirements and costs will be determined following detailed studies. These studies will consider your specific project location, operating characteristics and timing. Additionally, environmental and other required permits are independent of interconnection process and may limit the suitability of a particular site.

For questions about the System Data Portal, and to find more information about interconnecting Distributed Generation, please see the following website: RI Distributed Generation.

Help Guide and Terms of Use

To help enable the use of the portal, National Grid has provided a user guide in PDF. This can be accessed here: Rhode Island System Data Portal User Guide.

For the most refreshed view of the portal, please clear your internet browser cache periodically.

Additionally, please review the National Grid Rhode Island System Data Portal Terms of Use prior to using the portal.

Participating in Opportunities

For vendors, developers, and third-party solution providers seeking to participate in National Grid's Non-Wires Alternative (NWA) and other project and partnership opportunities, you will need to be enrolled in National Grid's Ariba vendor system.

Please contact Steven Hopengarten at steven.hopengarten@nationalgrid.com to request access to National Grid's Ariba system.

Once enrolled, please use the following link to access National Grid's Ariba system: http://nationalgrid.sourcing.ariba.com/.

Contact Us

For Inquiries related to this Portal, please contact IMAP@nationalgrid.com with the subject line: **RI System Data Portal**

Tab - FAQ

Rhode Island Energy™
a PPL company

Provides insight and information on FAQs of the Portal.

National Grid - Rhode Island System Data Portal

A story map

esri

Introduction | FAQ | Company Reports | Distribution Assets Overview | Heat Map | Hosting Capacity | Sea Level Rise | NWA

National Grid Rhode Island

FAQs

Are there instructions for using the Portal available?
National Grid has provided PDF user guides to help enable the use of the Portals:

Massachusetts System Data Portal: Massachusetts System Data Portal User Guide
New York System Data Portal: New York System Data Portal User Guide
Rhode Island System Data Portal: Rhode Island System Data Portal User Guide

Are there System Data Portals for National Grid's other service territories?
Yes! Here are the reference links for our System Data Portals:

Massachusetts System Data Portal:https://www.nationalgridus.com/Business-Partners/MA-System-Portal
New York System Data Portal: https://www.nationalgridus.com/Business-Partners/NY-System-Portal
Rhode Island System Data Portal: https://www.nationalgridus.com/Business-Partners/RI-System-Portal

Which web browsers work with the System Data Portals?
The recommended browser to access and use the Portal is Google Chrome. Others may work, however there may be limited functionality.

Are the System Data Portals mobile-friendly?
Yes! The System Data Portals can be viewed and interacted with from a smartphone or tablet.

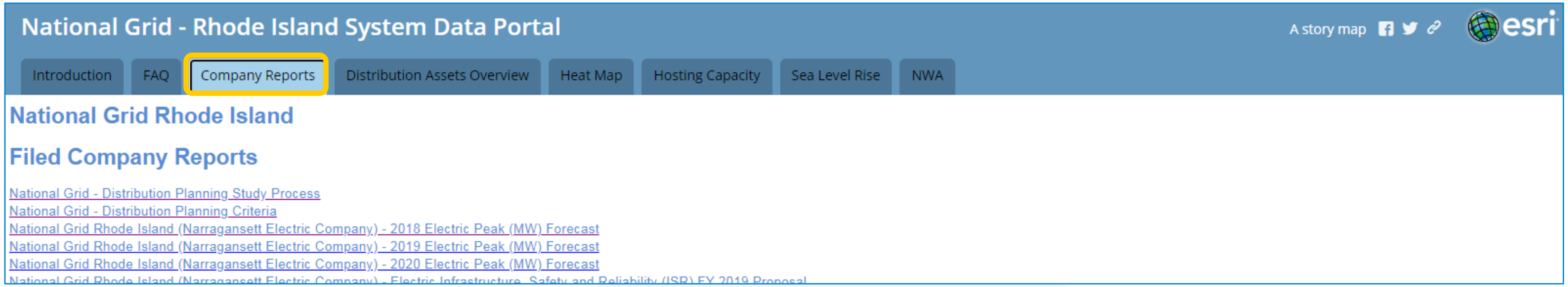
Is there any correlation between the color coding of the map tabs?
No. Each tab has their own color coding defined in the legend on that tab and are independent of one another in terms of how the colors are defined.

What's the update frequency of the Portal? Will this update frequency change?
The current update frequency for the Portal map data is on an annual basis, to reflect the summer peak data when distribution feeders and substations are typically most highly loaded. The current timeframe is around June of each year. This update frequency is acceptable for considering feeder loading in project planning and there are no plans currently to change this update frequency.

The update frequency for the Company Reports and NWA tabs data is as needed, which is usually every few months and therefore on a quarterly basis. The NWA tab is much easier to update since it is mostly text information versus the databases of the map tabs.

The distributed generation (DG) information tabulated on the Hosting Capacity (interconnected and pending) section will be updated monthly. The 3V0 substation information tabulated on the Hosting Capacity map will be updated monthly for Rhode Island and on an as-needed basis for New York.

Tab – Company Reports

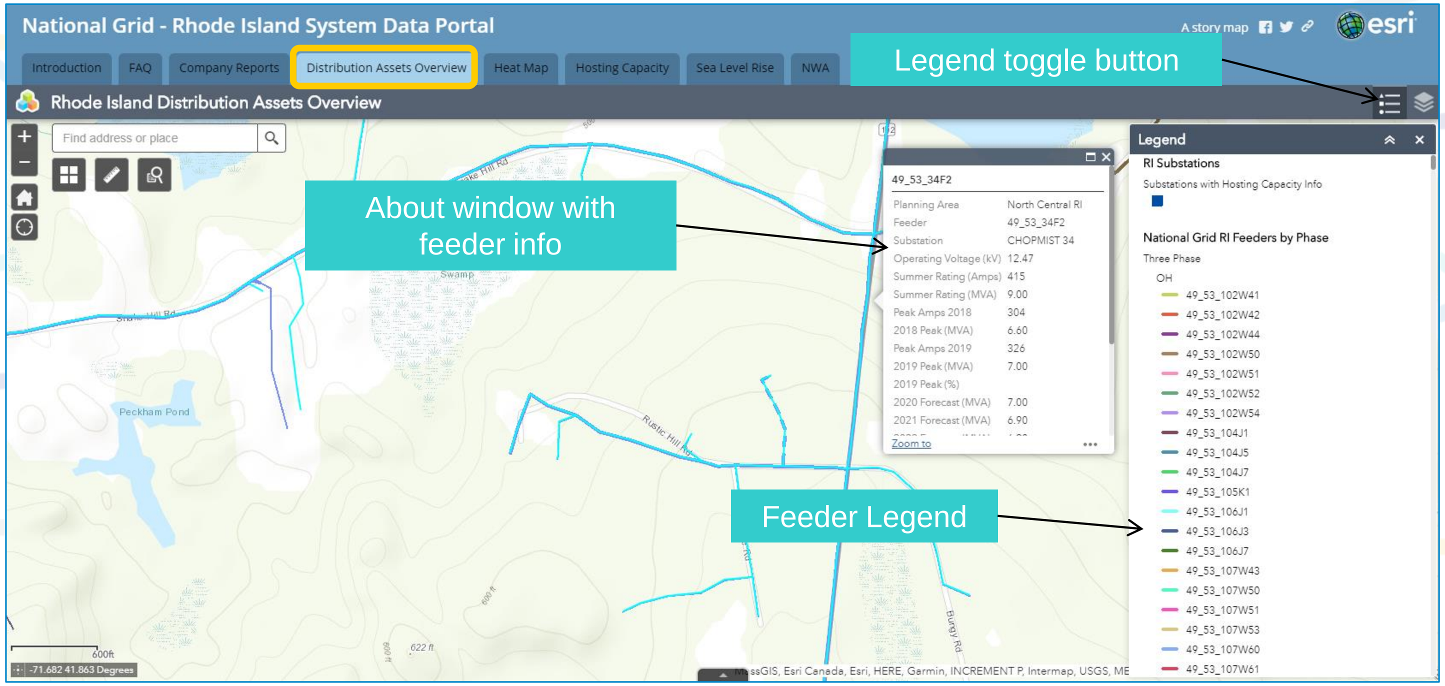


Provides links for various Regulatory Filings and Company Reports.

- Load forecasts and area studies for Rhode Island
- The Planning Criteria National Grid uses for its system
- A flowchart for RIE's Distribution Planning Process
- The annual SRP (System Reliability Procurement) Reports
- The FY2019 ISR (Electric Infrastructure, Safety and Reliability Plan) Filing

Tab – Distribution Assets Overview Map

- The Distribution Assets Overview tab shows RIE electric distribution assets, which includes circuits (feeders) by phase.
- Circuits are color coded by feeder name, on the Map and in the Legend.



Tab – Distribution Assets Overview Map

Rhode Island Energy™
a PPL company

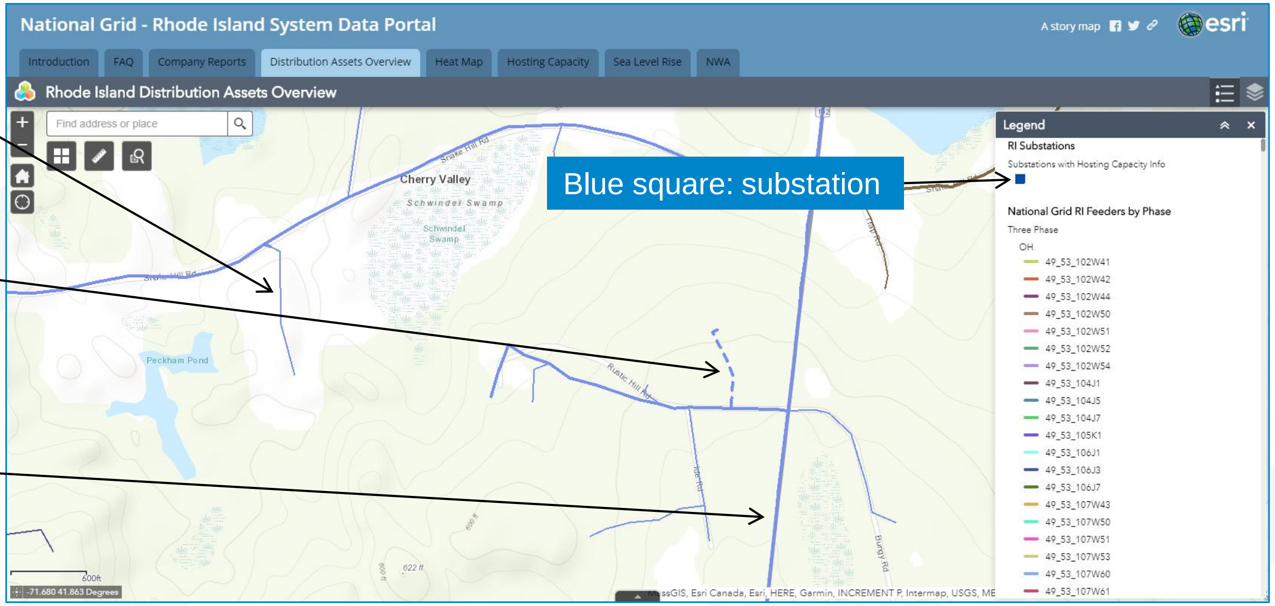
Circuit types are coded by line thickness and dash style.

- Thin lines denote single- or two-phase lines while thick lines denote three-phase.
- Solid lines denote overhead lines while dashed lines denote underground lines.

Thin solid line: single- or two-phase overhead section of circuit

Thick dashed line: three-phase underground section of circuit

Thick solid line: three-phase overhead section of circuit

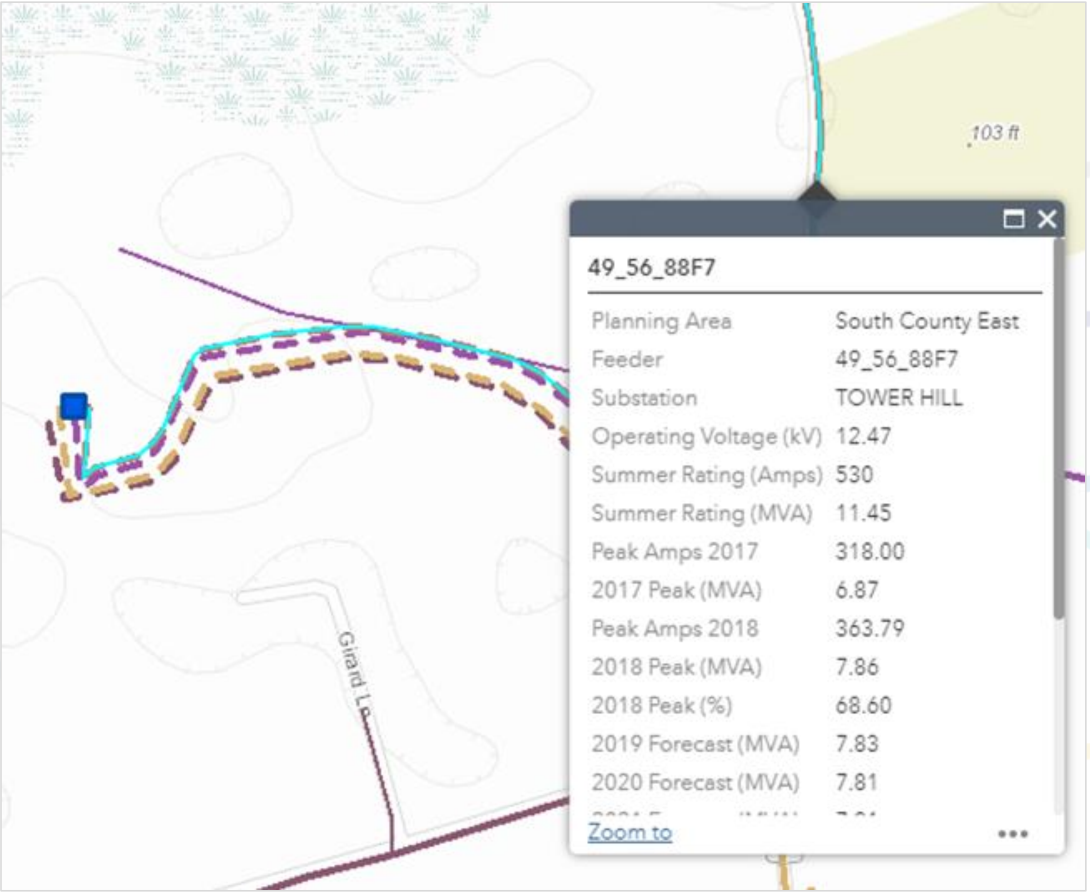


Tab - Distribution Assets Overview Map

Rhode Island Energy™
a PPL company

When selected, each feeder will reveal specific information.

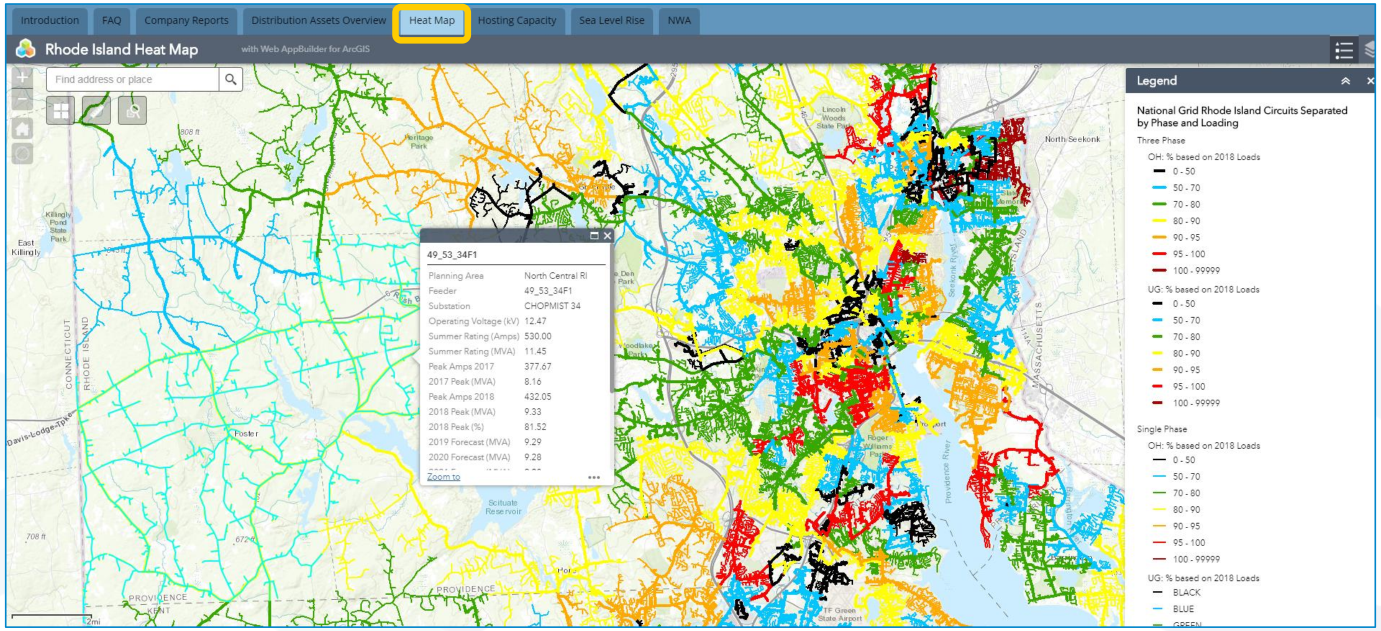
- Feeder ID
- Planning Area, Substation, and Operating Voltage
- Summer Rating
- Loading information for 10 years in the future



Tab – Heat Map

Rhode Island Energy™
a PPL company

- The Heat Map shows RIE electric distribution assets, similar to the Distribution Assets Overview tab. Circuits are color coded by the latest analysis year % Forecasted loading, as stated in the layer list.
- Feeder selection will display a variety of operating attributes and data.



Tab – Heat Map

Rhode Island Energy™
a PPL company

The Heat Map is an interactive map that displays relevant electric load information for the RIE electric distribution network in Rhode Island.

The Rhode Island electric distribution circuits shown on this interactive Heat Map are color coded based on their most recent annually forecasted percent loading, with the specific year identified in the map legend (e.g., 2019 Load/Feeder Rating). This information is intended to help Distributed Energy Resource (DER) developers identify distribution circuits that are loaded to 80% or more of their Summer Normal (SN) feeder rating. This interactive map is also intended to identify where additional capacity exists and can accommodate beneficial electrification of high efficiency heat pumps and electric vehicles (EVs), and to help EV infrastructure developers identify locations on the RIE electric distribution network.

The Heat Map legend details corresponding color-coding for feeder loading and the Known Transportation Vehicle Fleet Location markers.

Tab – Heat Map

Rhode Island Energy™
a PPL company

The “Known Transportation Vehicle Fleet Location” layer may be enabled/disabled through the map layer list. Known locations of transportation vehicle fleets are identified through open and public data sources: OpenStreetMap and RIGIS.

The “Potential Available Load Capacity (MVA)” value in the feeder detail pop-up illustrates the potential available capacity on the feeder for additional load and is calculated from the following formula:

“Potential Available Load Capacity” = “Summary Rating (MVA)” – “[Year] Peak (MVA)”

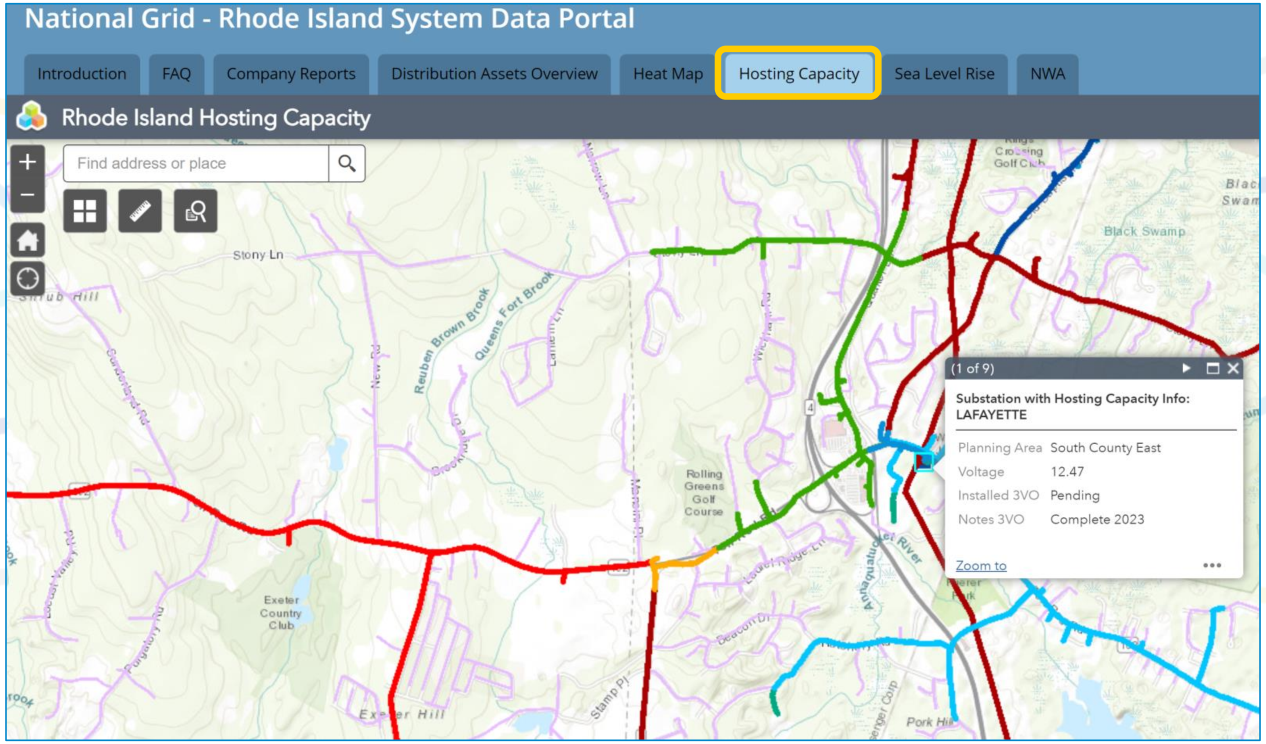
with the “[Year]” as the most recent calendar year provided in the feeder detail pop-up (e.g., “2019 Peak (MVA)” following the 2019 dataset update). This value, coupled with the detail provided by the heat map color-coded layer, can help provide insight to project, load, and electric infrastructure planning.

Note that this value is informative rather than prescriptive for planning purposes and may differ depending on feeder conditions throughout the year. The most up-to-date information for EV infrastructure and grid solution providers is best acquired through project contact channels.

Tab – Hosting Capacity Map

Rhode Island Energy™
a PPL company

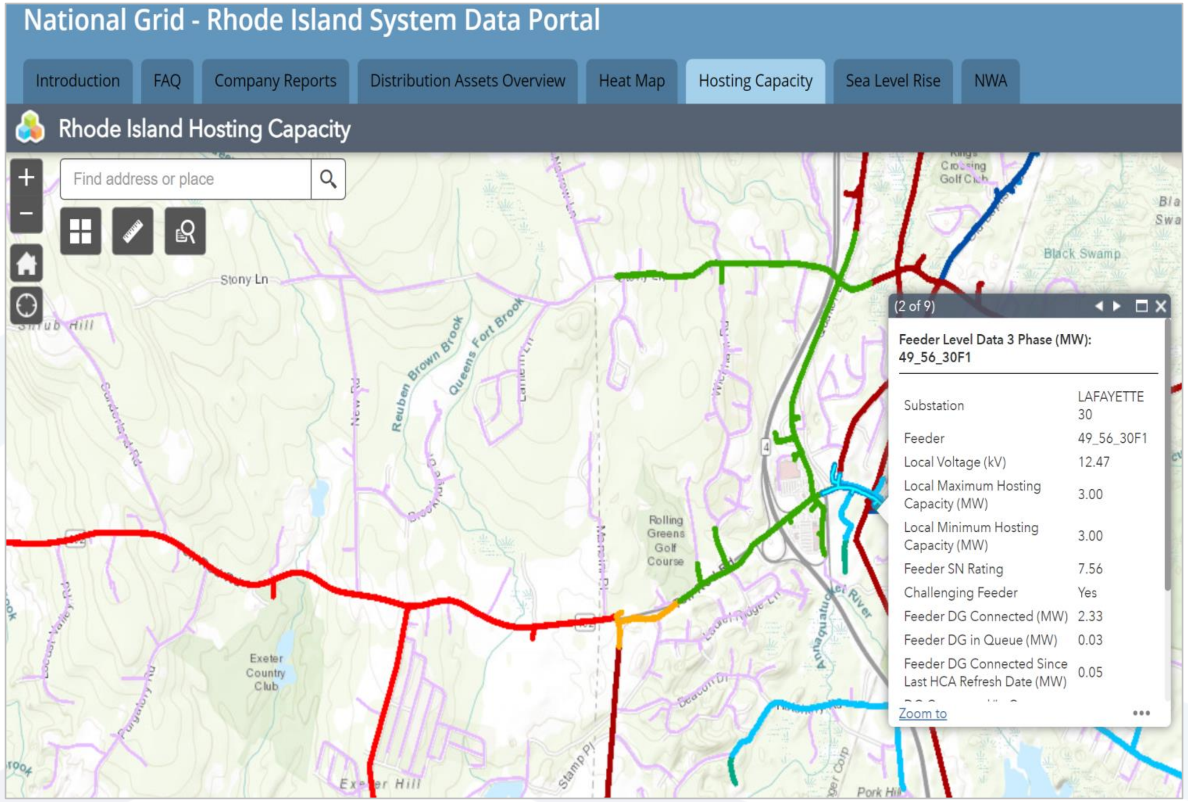
The Hosting Capacity Map shows RIE Substation 3V0 status, whether installed or pending and proposed year of completion.



Tab – Hosting Capacity Map

Rhode Island Energy™
a PPL company

- The Hosting Capacity Map also shows, at a feeder level, how much DER is interconnected, how much is proposed (in the queue), and additional relevant hosting capacity information.
- The Hosting Capacity Map was updated with nodal level hosting capacity results as of October 2021.
- The Hosting Capacity Map features selectable groups of nodes that have hosting capacity within a similar range.



Tab – Hosting Capacity Map

Rhode Island Energy™
a PPL company

The analyses presented in this map provide the grouped nodal level hosting capacity for the distribution circuits evaluated. Hosting Capacity is an estimate of the amount of DER that may be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades.

Please note that this analysis was conducted under current configurations, with interconnected DER (at the time of refresh), and prior to infrastructure upgrades such as; installing a recloser or remote terminal unit at the Point of Common Coupling, replacing a voltage regulating device or controller to allow for reverse flow, substation-related upgrades including 3V0 protection, or other protection-related upgrades.

Tab – Hosting Capacity Map

The analyses do not account for all factors that could impact interconnection costs (including substation constraints).

Please note that issues related to circuit protection require further analysis to make a definitive determination of hosting capacity. This data is being provided for informational purposes only and is not intended to be a substitute for the established interconnection application process.

The hosting capacity at any given location within a selected group of nodes will be between the "Local Maximum Hosting Capacity (MW)" and "Local Minimum Hosting Capacity (MW)" specified in the pop-up data.

Tab – Hosting Capacity Map

Rhode Island Energy™
a PPL company

The local minimum/maximum hosting capacity value is indicative of the available hosting capacity within the group selected.

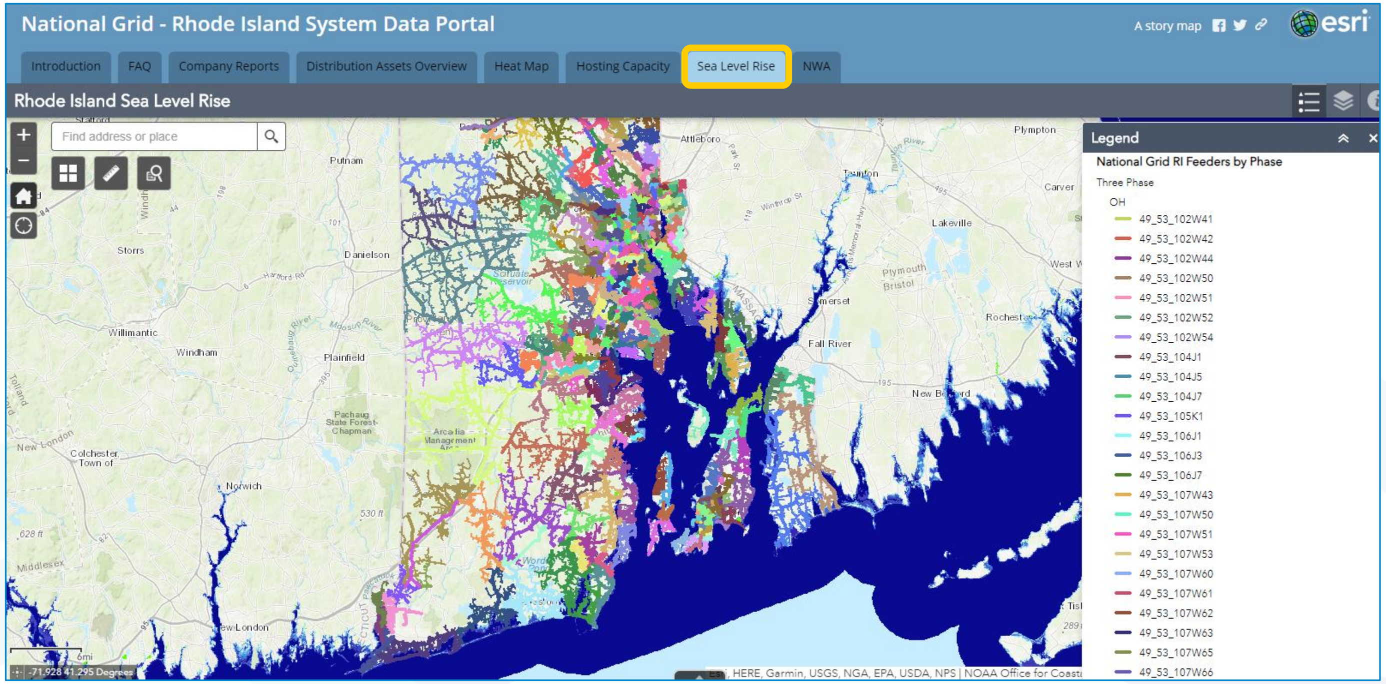
Existing DER, connected before the current hosting capacity analysis was performed, is included in the current hosting capacity data. The data pop-ups are intended to provide additional context to the displays.

The installed and queued DG values in the data pop-ups will continue to be included and will be updated on a monthly basis. An additional data point has been added to indicated the amount of DG nameplate that had been interconnected since the last HC refresh.

Tab – Sea Level Rise Map

Rhode Island Energy™
a PPL company

The Sea Level Rise Map overlays National Oceanic and Atmospheric Administration (NOAA) federal sea level rise map data with RIE's electric distribution network map data in Rhode Island.



Tab – Sea Level Rise

The Sea Level Rise Map is an interactive map that overlays National Oceanic and Atmospheric Administration (NOAA) federal sea level rise map data with National Grid's electric distribution network map data in Rhode Island.

This map provides information intended to help third-party solution providers and DER developers identify locations on the RIE electric distribution network in relation to areas that may experience potential coastal flooding impacts in the future.

All sea level rise data is sourced from the NOAA Sea Level Rise Viewer:

"NOAA Sea Level Rise Viewer." *NOAA Sea Level Rise and Coastal Flooding Impacts*, National Oceanic and Atmospheric Administration of the United States Department of Commerce, https://coast.noaa.gov/slr/.

Tab – Sea Level Rise

Rhode Island Energy™
a PPL company

NOAA Sea Level Rise Map source data DISCLAIMER:

“Water levels are relative to local Mean Higher High Water Datum. Areas that are hydrologically connected to the ocean are shown in shades of blue (darker blue = greater depth).

Low-lying areas, displayed in green, are hydrologically "unconnected" areas that may also flood. They are determined solely by how well the elevation data captures the area’s drainage characteristics. The mapping may not accurately capture detailed hydrologic/hydraulic features such as canals, ditches, and storm water infrastructure. A more detailed analysis, may be required to determine the area’s actual susceptibility to flooding.

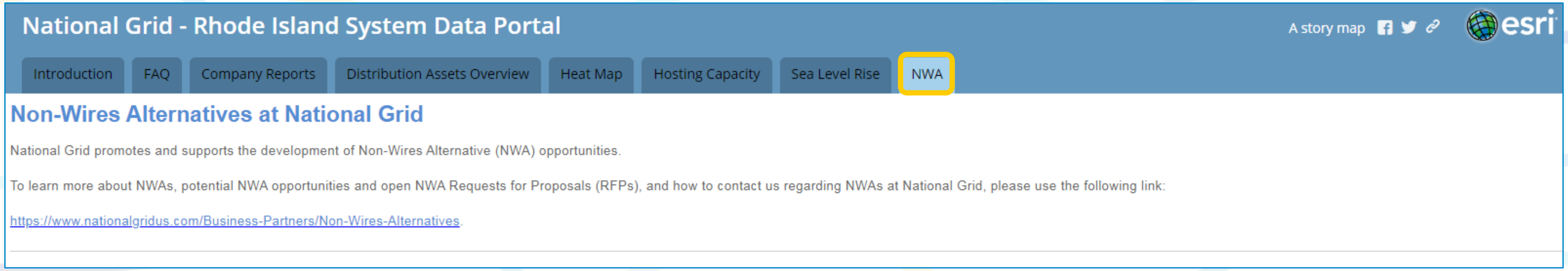
There is not 100% confidence in the elevation data and/or mapping process. It is important not to focus on the exact extent of inundation, but rather to examine the level of confidence that the extent of inundation is accurate.”

Tab - NWA

Rhode Island Energy™
a PPL company

The Portal also has a tab for Non-Wires Alternative information.

This NWA tab contains a link to the RIE Non-Wires Alternative homepage, which is the central source of RIE NWA info and references.



Rhode Island Energy™
a PPL company

Appendix 6. Electric System Reliability Procurement Benefit-Cost Assessment Model

See attachment. No proposed changes.

The Company provided the Excel version of Appendix 6.

Appendix 7. Electric System Reliability Procurement Technical Reference Manual

See attachment. No proposed changes.

Rhode Island Energy's Technical Reference Manual

for the

Benefit-Cost Analysis

of

Non-Wires Alternatives

in

Rhode Island

For use by and prepared by

The Narragansett Electric Company
d/b/a Rhode Island Energy

Table of Contents

RHODE ISLAND ENERGY's NON-WIRES ALTERNATIVES BENEFIT-COST ANALYSIS TECHNICAL REFERENCE MANUAL

1. Introduction

Rhode Island Energy's[1] Rhode Island Non-Wires Alternatives Benefit-Cost Analysis Technical Reference Manual (RI NWA BCA TRM) details how the Company assesses cost-effectiveness of Non-Wires Alternative (NWA) opportunities planned in Rhode Island through the Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model (RI NWA BCA Model). This cost-effective assessment is in alignment with the Rhode Island Benefit Cost Test (RI Test) as detailed in the Docket 4600 Benefit-Cost Framework[2] and in accordance with Sections 1.3(B) and 1.3(C) of the Least-Cost Procurement Standards (LCP Standards) as detailed in Docket 5015[3], with both dockets respectively approved by the Rhode Island Public Utilities Commission (PUC)[4]. Although the LCP Standards were originally developed for the Company's Energy Efficiency (EE) program, the same principles have been applied to other benefit-cost analyses (BCA) conducted by the Company at the request of the PUC, including the RI NWA BCA Model.

The following RI NWA BCA Model approach was based on the LCP Standards:

I. Assess the cost-effectiveness of the NWA portfolio per a benefit-cost test that builds on the Total Resource Cost Test (TRC Test) approved by the Public Utilities Commission (PUC) in Docket 4443[5], but that more fully reflects the policy objectives of the State with regard to energy, its costs, benefits, and environmental and societal impacts. Based on the Company's EE Program Plans, in consultation with the EERMC, it was determined that these benefits should include resource impacts, non-energy impacts, distribution system impacts, economic development impacts, and the value of greenhouse gas (GHG) reductions, as described below.

II. Apply the following principles when developing the RI Test:

   a. **Efficiency and Conservation as a Resource.** EE improvements and energy conservation are some of the many resources that can be deployed to meet customers' needs. It should, therefore, be compared with both supply-side and demand-side alternative energy resources in a consistent and comprehensive manner.
   b. **Energy Policy Goals.** Rhode Island's cost-effectiveness test should account for its applicable policy goals, as articulated in legislation (e.g., Resilient Rhode Island Act[6]), PUC orders, regulations, guidelines, and other policy directives.

[1] The Narragansett Electric Company d/b/a Rhode Island Energy (Rhode Island Energy or Company).

[2] "Docket No. 4600 and Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2 Nov. 2018, www.ripuc.ri.gov/eventsactions/docket/4600page.html.

[3] "Least Cost Procurement Standards." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 21 Aug. 2020, http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf.

[4] "RIPUC." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island, www.ripuc.ri.gov/.

[5] "Docket No. 4443." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 17 Sept. 2013, www.ripuc.ri.gov/eventsactions/docket/4443page.html.

[6] "Resilient Rhode Island Act of 2014 - Climate Change Coordinating Council." *Chapter 42-6.2*, State of Rhode Island and Providence Plantations, 2014, http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM.

c. **Hard-to-Quantify Impacts.** BCA practices should account for all relevant, important impacts, even those that are difficult to quantify and monetize.
d. **Symmetry.** BCA practices should be symmetrical, for example, by including both costs and benefits for each relevant type of impact.
e. **Forward Looking**. Analysis of the impacts of the investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of the NWA investment with those that would occur absent the investments (i.e., "Reference Case"). Sunk costs and benefits are not relevant to a cost-effectiveness analysis.
f. **Transparency.** BCA practices should be completely transparent, and should fully document and reveal all relevant inputs, assumptions, methodologies, and results.

III. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of carbon dioxide (CO_2) mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative (RGGI)[7]. The RI Test shall also include any other utility system costs associated with reasonably anticipated future greenhouse gas reduction requirements at the state, regional, or federal level for both electric and gas programs. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above (e.g., non-embedded or societal CO_2 costs). The RI Test may also include the costs and benefits of other emissions and their generation or reduction through LCP (e.g., nitrogen oxides (NOx), sulfur dioxide (SO_2)).

IV. Benefits and costs that are projected to occur over the project life of the individual NWA projects shall be stated in present value terms in the RI Test calculation using a discount rate that appropriately reflects the risks and opportunity cost of the investment.

[7] "State Statutes & Regulations - Rhode Island." *The Regional Greenhouse Gas Initiative*, RGGI, Inc., www.rggi.org/program-overview-and-design/state-regulations.

2. Overview of the Rhode Island Test

The RI Test compares the present value of a stream of **total benefits** to the **total costs** of the investment, **over the life** of that investment necessary to implement and realize the **net benefits**. The RI Test captures the value produced by the investment installed over the useful life of the investment. The investment life is based on the individual NWA contract timeframe and thus is expected to change on a per project basis.

The benefits calculated in the RI Test are primarily avoided resource (e.g., electric energy) supply and delivery costs, valued at marginal cost for the periods when there is a load reduction; and the monetized value of non-resource savings including avoided costs compared to a Reference Case (e.g., avoided utility capital and operations and maintenance (O&M) costs). The costs calculated in the RI Test are those borne by both the utility and by participants plus the increase in supply costs for any period when load is increased. All capital expenditure (CAPEX) (e.g., equipment, installation) and operational expenditure (OPEX) (e.g., evaluation and administration) are included.

All savings included in the value calculations are net savings. The expected net savings are typically an engineering estimate of savings modified to reflect the actual realization of savings based on evaluation studies, when available. The expected net savings also reflect market effects due to the program (*e.g.*, Demand Reduction Induced Price Effects (DRIPE)).

In accordance with Section 1.3.B of the revised Standards, Rhode Island Energy adheres to the RI Test for all NWA investment proposals. Rhode Island Energy has developed the RI NWA BCA Model, which is a derivative of the RI Test and utilizes the same Docket 4600 Benefit-Cost Framework, to more accurately assess NWA opportunities benefits and costs. The benefit categories and formulas in the RI NWA BCA Model are detailed in Section 3.

3. Description of Program Benefits and Costs

Table 1 summarizes the benefits and costs included in the RI Test and how they are treated in the Company's NWA BCA. Note that an "X" indicates that the category is quantified while an "O" indicates the category is unquantified, as applicable for RI NWAs. The "Docket 4600 Category" column in the table below references the categories and their respective details listed within Appendix A of Docket 4600.[8]

Table 1. Summary of RI Test Benefits and Costs and Treatment

RI Test Category	Docket 4600 Category	NWA	Notes
Electric Energy Benefits	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power System Level)	X	
	Retail Supplier Risk Premium (Power System Level)	X	
	Criteria Air Pollutant and Other	X	
	Distribution System Performance (Power System Level)	X	
Renewable Portfolio Standards (RPS) and Clean Energy Policies Compliance Benefits	REC Value (Power System Level)	X	
	GHG Compliance Costs (Power System Level)	X	
	Environmental Externality Costs (Power System Level)	X	
Demand Reduction Induced Price Effects	Energy DRIPE (Power System Level)	X	
Electric Generation Capacity Benefits	Forward Commitment Capacity Value (Power System Level)	X	
Electric Transmission Capacity Benefits	Electric Transmission Capacity Value (Power System Level)	X	
	Electric Transmission Infrastructure Costs for Site-Specific Resources	X	
Electric Distribution Capacity Benefits	Distribution Capacity Costs (Power System Level)	X	
Natural Gas Benefits	Participant non-energy benefits: oil, gas, water, wastewater (Customer Level)	O	(1)
Delivered Fuel Benefits		O	
Water and Sewer Benefits		O	
Value of Improved Reliability	Distribution System and Customer Reliability/Resilience Impacts (Power System Level)	X	
Non-Energy Impacts	Distribution Delivery Costs (Power System Level)	O	(2)
	Distribution system safety loss/gain (Power System Level)	O	
	Customer empowerment and choice (Customer Level)	O	

[8] "Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 3 Aug. 2017, www.ripuc.ri.gov/eventsactions/docket/4600A-PUC-GuidanceDocument-Notice_8-3-17.pdf. Appendix A.

RI Test Category	Docket 4600 Category	NWA	Notes
	Utility low income (Power System Level)	O	
	Non-participant rate and bill impacts (Customer Level)	O	
Non-Embedded GHG Reduction Benefits	GHG Externality Cost (Societal Level)	X	
Non-Embedded NOx Reduction Benefits	Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)	X	
Non-Embedded SO_2 Reduction Benefits	Public Health (Societal Level)	X	
Economic Development Benefits	Non-energy benefits: Economic Development (Societal Level)	O	(3)
Utility Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or Distributed Energy Resources costs	X	
Participant Costs	Program participant / prosumer benefits / costs (Customer Level)	X	
Notes (1) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e., NWAs). (2) Currently do not have data to claim benefits for a targeted need case. (3) Sensitivity analysis is currently under development. This benefit is negligible unless sensitivity analysis determines otherwise.			

The following additional Docket 4600 Benefit Categories require further analysis to determine the appropriate methodology and magnitude of quantitative or qualitative impacts:

- Low-income participant benefits (Customer Level)
- Forward commitment avoided ancillary services value (Power System Level)
- Net Risk Benefits to Utility System Operations from Distributed Energy Resource (DER) Flexibility & Diversity (Power System Level)
- Option value of individual resources (Power System Level)
- Investment under uncertainty: real options value (Power System Level)
- Innovation and learning by doing (Power System Level)
- Conservation and community benefits (Societal Level)
- Innovation and knowledge spillover - related to demo projects and other Research, Design, and Development (RD&D) (Societal Level)
- Societal low-income impacts (Societal Level)
- National security and US international influence (Societal Level)

All quantified NWA benefits are directly associated with the development of non-wires compared to a Reference Case with no NWA options. The source for many of the avoided cost value components is the "Avoided Energy Supply Components in New England: 221 Report" (AESC 2021 Study) prepared by Synapse Energy Economics for AESC 2021 Study Group, March, 2021.[9] This report was sponsored by the

[9] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

electric and gas EE program administrators of Rhode Island Energy in New England and is designed to be used for cost-effectiveness screening in 2019 through 2021.

The AESC Study determines projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels, as well as avoided environmental compliance costs resulting from EE and other conservation programs. The AESC study is prepared every three years for the AESC Study Group, which is comprised of the Program Administrators as detailed in the AESC Study, as well as utilities throughout New England and other interested non-utility parties.

The AESC Study provides projections of avoided costs of energy in each New England state for a hypothetical future in which a myriad of EE and DER opportunities exist. In the 2021 AESC study four counterfactual cases exist based upon the inclusion of energy efficiency, building electrification, and active demand management. For the purpose of this BCA counterfactual #2 was utilized. This is the most inclusive counterfactual including energy efficiency and active demand management being utilized in 2021 and later years. This counterfactual does not include future building electrification but due to the limitations of the various models it is determined to be the most applicable for NWAs.

The RI NWA BCA methodology is technology agnostic and should be broadly applicable to all anticipated project and portfolio types, with some adjustments as necessary. Specific technology's availability during the specified system need time may differ. This technology coincidence factor is based upon the association between the system, transmission, and distribution peak for the specified NWA need, as detailed in Section 5.2 of National Grid's New York BCA Handbook.[10] These generalized values are subject to change.

3.1 Electric Energy Benefits

Electric energy benefits due to NWA implementation can be a result of reduced energy usage (e.g., targeted EE or DR), a shift of usage from peak to off-peak (e.g., battery storage), or energy generation (e.g., solar). The resulting avoided electric energy costs are appropriate benefits for inclusion in the RI NWA BCA Model. Electric energy benefits are valued using the avoided electric energy costs developed in the AESC 2021 Study, Appendix B.[11]

Avoided costs may be viewed as a proxy for market costs. However, avoided costs may be different from wholesale market spot costs because avoided costs are based on simulation of market conditions, as opposed to real-time conditions. They may be different from standard offer commodity costs because of time lags and differing opinions on certain key assumptions, such as short-term fuel costs.

AESC's wholesale cost of electric energy includes pool transmission losses (PTL) incurred from the generator to the point of delivery to the distribution companies, while AESC's retail cost of electric energy includes the wholesale cost plus the cost of renewable energy credits (RECs) borne by generators (i.e.,

[10] "National Grid Version 2.0 Benefit-Cost Analysis (BCA) Handbook." *National Grid Non-Wires Alternatives: Additional Information*, Niagara Mohawk Corporation d/b/a National Grid, 31 July 2018, www.nationalgridus.com/media/pdfs/bus-partners/ny_bca_handbook_v2.0.pdf.

[11] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix B*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

embedded GHG costs), wholesale risk premium (WRP) that captures market risk factors typically recovered by generators in their pricing,[12] and distribution losses incurred from the Independent System Operator (ISO) delivery point to the end-use customer. In the RI NWA BCA benefits calculation, energy savings are grossed up using factors that represent transmission and distribution losses, situation dependent, because a reduction in energy use at the end user means that amount of energy does not have to be generated, plus the extra generation that is needed to cover the losses that occur in the delivery.

AESC's avoided energy cost values also internalize the expected cost of complying with current or reasonably anticipated future regional or federal greenhouse gas reduction requirements, which are borne by generators and passed through in wholesale costs.

Both the wholesale and retail costs of electric energy in the AESC 2021 Study are provided in four different costing periods consistent with ISO New England Inc. (ISO-NE) definitions. Net energy savings are apportioned into these periods in the value calculation. The time periods are defined as follows:

- Winter Peak: October – May, 7:00 a.m. – 11:00 p.m., weekdays excluding holidays.
- Winter Off-Peak: October – May; 11:00 p.m. – 7:00 a.m., weekdays. Also, including all weekends and ISO defined holidays.
- Summer Peak: June – September, 7:00 a.m. – 11:00 p.m., weekdays excluding holidays.
- Summer Off-Peak: June – September; 11:00 p.m. – 7:00 a.m., weekdays. Also, including all weekends and ISO defined holidays.

NWA system needs have targeted time of use that fall within the above time periods. Each system need will therefore have a specific ratio of the four time periods. Energy savings for NWAs are allocated to the targeted times and multiplied by the appropriate avoided energy value. Generally, the system need is occurring during summer peak.

In cases where an energy use transfer occurs (e.g., battery storage) energy reductions and increases could occur across time periods. Each time period is calculated separately and then added together resulting in a net monetized energy reduction value. Furthermore, in solutions with energy losses as part of the technology solution (e.g., battery storage, solar) a round trip/efficiency loss modifier is utilized.

To account for the value of embedded CO_2 costs (i.e., RECs) separately in the RI NWA BCA Model, AESC's wholesale cost of electric energy values is used as the basis for electric energy savings benefits. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. These benefit values are then grossed up using the appropriate WRP that captures market risk factors typically recovered by generators in their pricing,[13] and distribution loss factors representing losses from the ISO delivery point to the end-use customer.

[12] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.
[13] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.

The AESC 2021 Study assumes 9% for marginal system losses.[14] Marginal losses are more in line with the peaking nature of NWA use cases. This is similar to the Company's distribution loss estimate of 6.9% for "Secondary Voltage" customers, which are predominantly residential and small commercial customers (e.g., Rates A-16, A-60, C06, G02)[15], plus the Company's non-PTF transmission loss estimates of 0.07%.

Each technology then has a rating factor that is applied based on its system need coincidence.

The dollar value of annual benefits is therefore calculated as:

- Summer Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings $\text{ElectricEnergyCost}_{\text{SumPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Summer Off-Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{SumOffPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{WinPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Off-Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{WinOffPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- ElectricEnergyCost ($/kWh) = Projected annual values for each time period (AESC 2021, Appendix B, "Wholesale Cost of Electric Energy")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss" ISO-NE default value)
- %Inflation = 2% (AESC 2021, Appendix E, page 327)

3.2 RPS and Clean Energy Policy Compliance Benefits

This benefit category captures the value of avoided embedded CO_2 and SO_2 costs separately from the "Environmental and Public Health Benefits" category. These RPS and Clean Energy Policy compliance benefits due to NWAs are the results of the reduced energy usage as described in Section 3.1.

[14] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix B*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[15] "Tariff Provisions." *National Grid: Bills, Meters & Rates*, National Grid US, www.nationalgridus.com/RI-Business/Rates/Tariff-Provisions.

The resulting avoided RPS and Clean Energy Policy (i.e., RGGI) compliance costs are appropriate benefits for inclusion in the RI NWA BCA Model. When customers do not have to purchase electric energy because of an investment an avoided RPS and Clean Energy Policy compliance benefit is created. These compliance benefits are valued using the avoided wholesale REC costs developed in the AESC 2021 Study, Appendix B.[16] Due to the expanding geographical footprint of the RGGI initiative, and the electricity usage now being dominated by states outside of New England, the AESC treats the effects of RGGI as an exogenous price.

SO_2 emissions pricing is determined by the allowance under the Cross-State Air Pollution Rule (CASPR) and the Acid Rain Program (ARP). The 2020 SO_2 spot auction resulted in a price of $0.02 per short ton. No embedded NOx pricing is assumed.

Nominal annual benefits are calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. These benefit values are then grossed up using the appropriate WRP that captures market risk factors typically recovered by generators in their pricing,[17] and distribution loss factor representing losses from the ISO delivery point to the end-use customer. Each technology then has a rating factor that is applied based on its system need coincidence. Furthermore, in solutions with energy losses as part of the technology solution (e.g., battery storage, solar) a round trip/efficiency loss modifier is utilized.

The dollar value of the annual benefits is therefore calculated as:

- RPS and Clean Energy Policy Compliance Benefit ($/yr) = ElectricEnergySavings kWh/yr * (RGGICompliance $/kWh + SOx Embedded) * TechnologyCoincidence * EfficiencyLoss * (1 + %Inflation)^(year-2021) * (1 + WRP) * (1 + %Losses)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- RGGICompliance ($/kWh) = Projected annual values (AESC 2021, Appendix B, "REC Costs")
- SOx Embedded ($/kWh) = Projected annual values (AESC 2021, Page 107)[18]
- %Inflation = 2.00% (AESC 2021, Appendix E, Page 327)
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses = 9% (AESC 20218, Appendix B, " Marginal Loss" ISO-NE default value)
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution

3.3 Demand Reduction Induced Price Effects

[16] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[17] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.

[18] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf Page 107

DRIPE is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to reduced demand from electric system investments. These electric system investments can include NWAs. These investments avoid both marginal energy production and capital investments, but also lead to structural changes in the market due to lower demand. Over a period of time, the market adjusts to lower demand, but until that time the reduced demand leads to a reduction in the market price of the energy commodity. This is observed in the New England market when ISO-NE activates its price response programs. When this price effect is a result of NWAs, it is appropriate to include the impact in the RI NWA BCA Model.

DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms over all the kWh and kW transacted in the market. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. AESC provides values for two types of DRIPE benefits, Intrastate and Rest of Pool (ROP). Intrastate DRIPE takes credit for the reduced clearing price for Rhode Island customers, while ROP DRIPE takes credit for the reduced clearing price for customers across New England. The base case BCA results exclude ROP DRIPE to align with standard industry practice.

Intrastate Energy, Capacity, and Cross DRIPE values developed for the AESC 2021 Study are used in the RI NWA BCA Model. Wholesale Energy DRIPE values in the AESC 2021 Study are provided in four different costing periods consistent with ISO-New England (ISO-NE) definitions. Net energy savings are split up into these periods in the value calculation. See Section 3.1 for time period definitions. Both wholesale and retail Capacity DRIPE values are provided in the AESC 2021 Study on an annual basis. AESC also provides annual wholesale Cross DRIPE values to account for natural gas price effects caused by a change in electricity generation demand. Each technology then has a rating factor that is applied based on its system need coincidence. Furthermore, in solutions with energy losses as part of the technology solution (e.g., battery storage, solar) a round trip/efficiency loss modifier is utilized.

Capacity DRIPE is valued differently in the AESC report depending upon whether the benefit results from resources that are bid into the Forward Capacity Market (FCM) (i.e., cleared resources) or reductions in peak demand that are not bid into the FCM (i.e., uncleared resources). For NWA solutions the DRIPE avoided cost forecast for uncleared resource values is used. AESC assumes a lag of 5 years between the appearance of the load reduction and the realization of the Capacity DRIPE benefits for uncleared resources (e.g., load reductions in 2021 results in benefits in 2026). To maintain that lag, DRIPE capacity benefits are shifted based on the commercial operating date of the NWA solution.

Energy and Cross DRIPE benefits are also shifted based on the commercial operating date, but the benefits are realized the year after installation, with the $/kWh avoided costs shifted forward one year and escalated by one year of inflation. Loss factors are applied to the wholesale Energy and Cross DRIPE values to account for local transmission and distribution (T&D) losses from the point of delivery to the distribution company's system to the ultimate customer's facility. Wholesale Capacity DRIPE values are used in the RI NWA BCA Model calculations and then T&D loss factors applied. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Capacity DRIPE's demand savings are calculated to be coincident with the ISO-NE definition of the peak, which is in the summer.

The dollar value of annual benefits is therefore calculated as:

- Summer Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings ElectricEnergyCost$_{SumPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Summer Off-Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{SumOffPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{WinPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Off-Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{WinOffPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Cross DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * CrossDRIPE $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Generation Capacity DRIPE Benefit ($/yr) = ElectricDemandSavings kW/yr$_{SumPk}$ * WholesaleCapDRIPE $/kW-yr * TechnologyCoincidence * (1 + WRP) * (1 + %Losses$_{Cap}$) * (1 + %Inflation)^(year-2021)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- ElectricDemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- EnergyDRIPE ($/kWh) = Projected annual values (AESC 2021, Appendix B, "Intrastate - Wholesale Energy DRIPE")
- CrossDRIPE ($/kWh) = Projected annual values (AESC 2021, Appendix B, "Intrastate – Wholesale Cross DRIPE")
- RetailCapDRIPE ($/kW-yr) = Projected annual values (AESC 2021, Appendix B, "Intrastate – Capacity DRIPE – Uncleared")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss" ISO-NE default value)
- %Losses$_{Cap}$ = 16% (AESC 2021, Appendix B, "Marginal Loss Capacity" ISO-NE default value)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.4 Electric Capacity Benefits

At the generation and transmission level, electric capacity benefits due to NWAs are a result of load reductions at summer peak. At the distribution and site-specific transmission level, electric capacity benefits are a result of the deferred system upgrade. This value is an avoided cost based on a time-deferred expected project cost of the system upgrade.

3.4.1 Electric Generation Capacity Benefits

When generators do not have to build new generation facilities or when construction can be deferred because of NWAs, an avoided electric energy resource benefit is created. In the New England capacity market, capacity benefits accrue because demand reduction reduces ISO-NE's installed capacity requirement. The capacity requirement is based on avoided load's contribution to the system peak, which, for ISO-NE, is the summer peak. Generation capacity avoided costs are driven by load at the time of the ISO-NE peak, which has by convention associated with an hour ending at 3 PM or 5 PM on a hot summer day.[19] Therefore, capacity benefits accrue only from summer peak demand reduction; there is currently no winter generation capacity benefit for ISO-NE.

Peak demand savings created through NWAs are valued using the avoided wholesale capacity values from the 2021 AESC, Appendix B. The values are then grossed up to account for wholesale risk premium (WRP) and distribution losses. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Demand savings are calculated to be coincident with the ISO-NE definition of peak, which is in the summer.

The dollar value of annual benefits is therefore calculated as:

- Generation Capacity Benefit ($/yr) = ElectricDemandSavings kW/yr$_{\text{SumPk}}$* CapCost $/kW-yr * %Summer Coincidence * TechnologyCoincidence * (1+WRP) * (1+%Losses$_{\text{Cap}}$) * (1 + %Inflation)^(year-2021)

Where:

- ElectricDemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- WholesaleCapCost ($/kW-yr) = Projected annual values (AESC 2021, Appendix B, "Wholesale Electric Capacity – Uncleared")
- %Summer Coincidence: % of NWA peak capacity at ISO peak
- TechnologyCoincidence: Coincidence factor applied based on the solution technology type
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses$_{\text{Cap}}$ = 16% (AESC 2021, Appendix B, "Marginal Loss Capacity" ISO-NE default value)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

The AESC 2021 Study includes two types of wholesale capacity values: 1) cleared capacity (Forward Capacity Auction (FCA) price), which is the traditional valuation of electric generation capacity, and 2) uncleared capacity, which is a new approach to valuing the capacity of short duration measures that are

[19] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Page 239.

not actively bid in the ISO-NE Forward Capacity Market (FCM). The AESC study provides these two values for avoided electric generation capacity, which are differentiated based on whether a load reduction is taken into account when bidding into the FCM (cleared capacity) or is not (uncleared capacity), and an overall weighted average avoided capacity value representing a weighted average of the cleared capacity and uncleared capacity values.

Given the three year forward nature of the FCM and the timing of the ISO-NE load forecast, it takes five years from the time of load reduction for uncleared capacity to begin impacting the FCM procurements. As a result, measures with a useful life less than five years (e.g., traditional demand response programs) would not produce any generation capacity benefits in years 1-5 under the traditional capacity modeling methodology.

NWAs will not be considered when bidding into the FCM, so the uncleared capacity values are used.

3.4.2 Electric Transmission Capacity Benefits

When transmission facilities do not have to be built or can be deferred because of NWAs, an avoided electric energy resource benefit is created. Electric transmission capacity benefits are valued in the RI Test based on the costs of Pool Transmission Facilities (PTF). The AESC 2021 Study calculates an avoided cost for PTF of $84/kW-year in 2021 dollars.

Capacity loss factors are applied to the avoided transmission capacity cost to account for local transmission and distribution (T&D) losses from the point of delivery to the distribution company's system to the ultimate customer's facility. Thus, T&D losses are accounted for from the generator to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Demand savings are calculated to be coincident with the ISO-NE definition of peak, which is in the summer.

The dollar value of annual benefits is therefore calculated as:

- Transmission Benefit ($/yr) = DemandSavings kW/yr$_{SumPk}$ * TransCapCost $/kW-yr * %Summer Coincidence * TechnologyCoincidence * (1 + %Losses$_{Avg}$) * (1 + %Inflation)^(year-2021) * TransmissionCoincidence

Where:

- DemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- TransCapCost ($/kW-yr) = $84/kW-year (AESC 2021, Appendix B, "T&D Cost")
- %Summer Coincidence = % of NWA peak capacity at ISO peak
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- %Losses$_{Avg}$ = 8% (AESC 2021, Page 333 "PTF Losses", "Average Loss Peak")
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)
- TransmissionCoincidence (%)= System Need (MW)/RI Capacity (MW)

3.4.3 Electric Distribution Capacity Benefits

Distribution Capacity benefit is based on the direct deferred distribution infrastructure due to the implementation of the NWA. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NWA.

3.4.4 Electric Transmission Infrastructure Site-Specific Benefits

Transmission Infrastructure Site-Specific benefit is based on the direct deferred transmission infrastructure due to the implementation of the NWA. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NWA. This value will typically be null for NWAs.

3.5 Natural Gas Benefits

An avoided resource benefit is produced when a project, in which customers have invested, reduces natural gas usage. Natural Gas benefits are negligible for NWAs, so they are not included in the RI NWA BCA Model calculations.

3.6 Delivered Fuel Benefits

An avoided resource benefit is produced when a project, in which customers have invested, reduces delivered fuel usage. Avoided delivered fuel costs (natural gas, propane, or fuel oil) are negligible for NWAs, so they are not included in the RI NWA BCA Model calculations.

3.7 Water and Sewer Benefits

An avoided resource benefit is produced when a project, in which customers have invested to save electricity or fuel, also reduces water consumption. Examples of reduced water consumption can include a cooling tower project that reduces makeup water usage or need. Water and sewer benefits are negligible for NWAs, so they are not included in the RI NWA BCA Model calculations.

3.8 Value of Improved Reliability

Due to the site-specific nature of these solutions, a reliability benefit should also be localized. The reliability benefit is currently difficult to quantify due to the new nature of the technologies that NWAs typically utilize. This benefit will be developed and applied as more projects are implemented and technology-specific reliability values are determined.

3.9 Non-Energy Impacts

Non-Energy Impacts (NEIs) can be produced as a direct result of NWA investments and are therefore appropriate for inclusion in the RI NWA BCA Model. Non-energy impacts may include but are not limited to: labor, material, facility use, health and safety, materials handling, national security, property values, and transportation. For income-eligible measures, NEIs also include the impacts of lower energy bills, such as reduced arrearages or avoided utility shut-off costs. These benefits are currently seen to be negligible for NWAs.

3.10 Environmental and Public Health Impacts

Environmental benefits due to NWAs are a result of reduced energy use from the implemented solution. The resulting avoided environmental costs are appropriate benefits for inclusion in the RI NWA BCA Model. Reduction in the use of electricity generated at central power plants provides environmental benefits to Rhode Island and the region, including reduced greenhouse gas emissions and improved air quality.

3.10.1 Non-Embedded Greenhouse Gas Reduction Benefits

Carbon dioxide and other GHG emissions come from a variety sources, including the combustion of fossil fuels like natural gas, coal, gasoline, and diesel. Increase in atmospheric CO_2 concentrations contributes to an increase in global average temperature, which results in market damages, such as changes in net agricultural productivity, energy use, and property damage from increased flood risk, as well as nonmarket damages, such as those to human health and to the services that natural ecosystems provide to society.[20]

According to the AESC 2021 Study, the cost of GHG emissions reductions can be determined based on estimating either carbon damage costs or marginal abatement costs. Damage costs in the AESC are sourced from the December 2020 SCC Guidance published by the State of New York. This guidance recommended a 15 year levelized price of $128 per short ton. Due to the many uncertainties in climate damage cost estimates, the AESC study concluded that the marginal abatement cost method should be used instead. This method asserts that the value of damages avoided, at the margin, must be at least as great as the cost of the most expensive abatement technology used in a comprehensive strategy for emission reduction.[21]

The AESC 2021 Study developed three approaches for calculating the non-embedded cost of carbon based on marginal abatement costs. Note that "non-embedded" costs are not included in AESC's modeling of energy prices, as opposed to "embedded" costs, which include costs associated with RGGI, SO_2 regulation programs.[22] The first approach is an estimate for the global marginal carbon abatement cost based on carbon capture and sequestration technology, which yields a value of $92 per short ton of CO_2 equivalent and is lower than the prior AESC 2018 Study[23] value used. The second approach is based on a New England specific marginal abatement cost, where it is assumed that the marginal abatement technology is offshore wind. The third approach assumes a New England specific cost derived from multiple sectors, not just electric.

The New England specific marginal abatement costs assume a $125 per short ton of CO2 emissions. This is based on the future cost trajectories of offshore wind facilities along the east coast of the United States. This aligns with New York Department of Environmental Conservation's 2020 valuation of $125 per ton. This value is used in this BCA model.

The costs of compliance with the RGGI are already included or "embedded" in the projected electric energy market prices. Therefore, the difference between the $125 per short ton societal cost and the RGGI compliance costs already embedded in the projected energy market prices represents the value of

[20] National Academies of Sciences, Engineering, and Medicine 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651.

[21] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Pages 171 to 182.

[22] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. See *Chapter 4. Common Electric Assumptions* for a discussion of how these costs are modeled.

[23] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/project/aesc-2018-materials

carbon emissions not included in the avoided energy costs. The AESC 2021 calculates this value at a $/kwh broken into winter/summer and peak/off-peak aligning with and not double counting the energy benefits calculated in section 3.1.

Loss factors are applied to the marginal emissions factor for ISO-NE generators to account for marginal losses from the generator to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- Non-Embedded GHG Reduction Benefit Summer Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{SumPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded GHG Reduction Benefit Summer Off-peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{SumOffPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded GHG Reduction Benefit Winter Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{WinPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded GHG Reduction Benefit Winter Off-Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{WinOffPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- Non-Embedded GHG Costs: Projected annual values for each time period (AESC 2021, Appendix B, "Non-Embedded GHG Costs")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss", ISO-NE default value) %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.10.2 Non-Embedded NOx Reduction Benefits

Nitrogen oxide (NOx) emissions come from a variety of sources including heavy duty vehicles, industrial processes, and the combustion of natural gas for electricity generation. NOx contributes to the formation of fine particle matter (PM) and ground-level ozone that are associated with adverse health effects including heart and lung diseases, increased airways resistance, which can aggravate asthma and other underlying health issues, and respiratory tract infections. In addition to known health impacts, PM pollution and ozone are also likely to contribute to negative climate impacts.[24]

In February, 2018, the US EPA published a Technical Support Document for estimating the benefit of reducing PM2.5 precursors from 17 sectors, including avoided NOx costs from "electricity generating units".[25] The EPA document estimates national average values for mortality and morbidity per ton of directly-emitted NOx reduced for 2016, 2020, 2025, and 2030 based on the results from two other studies.[26,27] Using the average results from the two studies the non-embedded NOx emissions cost to be $10,100 per ton in 2020 (2015 dollars). This translates into a $0.90 per MWh in 2020.
The AESC 2021 Study also estimates avoided NOx emissions costs utilizing a continental U.S. average, non-embedded NOx emission wholesale cost of $14,700 per ton of NOx (2021 dollars).[28] This translates to a $0.77 per MWh in 2021. The RI NWA BCA model utilizes the AESC 2021 value broken down into a winter/summer and peak/off-peak kWh value.

Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Loss factors are applied to the marginal emissions factor for ISO-NE generators to account for local T&D losses from the generator to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- Non-Embedded NOx Reduction Benefit Summer Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx $\text{Costs}_{\text{SumPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded NOx Reduction Benefit Summer Off-peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx $\text{Costs}_{\text{SumOffPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded NOx Reduction Benefit Winter Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx $\text{Costs}_{\text{WinPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded NOx Reduction Benefit Winter Off-Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx $\text{Costs}_{\text{WinOffPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)

[24] "Our Nation's Air: Status and Trends through 2019." *Our Nation's Air: Trends Report*, United States Environmental Protection Agency, 2020, https://gispub.epa.gov/air/trendsreport/2020.

[25] "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors (February 2018)." *US EPA Benefits Mapping and Analysis Program (BenMAP)*, United States Environmental Protection Agency, Feb. 2018, www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-17-sectors.

[26] Krewski D, Jerrett M, Burnett RT, Ma R, Hughes E, Shi Yet al., "Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality", Boston Health Effects Institute, 2009.

[27] Lepeule J, Laden F, Dockery D, and Schwartz J, "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009", EHP Vol 120 No. 7, July 2012.

[28] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Page 183

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- Non-Embedded NOx Costs: Projected annual values for each time period (AESC 2021, Appendix B, "Non-Embedded NOx Costs")
- TechnologyCoincidence = Coincidence Factor based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss", "ISO default")
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.10.3 Non-Embedded SO_2 Reduction Benefits

Sulfur dioxide (SO_2) emissions come from a variety of sources including industrial processes and the combustion of coal (especially high-sulfur coal) and fuel oil for electricity generation and heating. SO_2 contributes to the formation of fine PM that are associated with adverse health effects including heart and lunch diseases and increased airways resistance, which can aggravate asthma and other underlying health issues. In addition to known health impacts, PM pollution is also likely to contribute to negative climate impacts.[29]

In February, 2018, the US EPA published a Technical Support Document for estimating the benefit of reducing PM2.5 precursors from 17 sectors, including avoided SO_2 costs from "electricity generating units".[30] The EPA document estimates national average values for mortality and morbidity per ton of directly-emitted SO_2 reduced for 2016, 2020, 2025, and 2030 based on the results from two other studies.[31,32] Using the average of the results from the two studies, the RI NWA BCA Model estimates the SO_2 emissions cost to be $69,000 per ton of SO_2 in 2020 (2015 dollars) increasing to $79,500 per ton of SO_2 in 2030 (2015 dollars). These translate into $3.80 per MWh in 2020 and $4.6037 per MWh in 2030 (2015 dollars) using the ISO-NE 2019 marginal SO_2 emissions factor of 0.02 lb SO_2/MWh.[33] Nominal annual benefits are then calculated using an average inflation rate to convert the 2015 real dollar values to nominal values.

Loss factors are applied to the marginal emissions factor for ISO-NE generators to account for local transmission and distribution (T&D) losses from the generator to the end-use customer. Nominal annual

[29] "Our Nation's Air: Status and Trends through 2019." *Our Nation's Air: Trends Report*, United States Environmental Protection Agency, 2020, https://gispub.epa.gov/air/trendsreport/2020.

[30] "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors (February 2018)." *US EPA Benefits Mapping and Analysis Program (BenMAP)*, United States Environmental Protection Agency, Feb. 2018, www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-17-sectors.

[31] Krewski D, Jerrett M, Burnett RT, Ma R, Hughes E, Shi Yet al., "Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality", Boston Health Effects Institute, 2009.

[32] Lepeule J, Laden F, Dockery D, and Schwartz J, "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009", EHP Vol 120 No. 7, July 2012.

[33] "2019 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., March 2021, https://www.iso-ne.com/static-assets/documents/2021/03/2019_air_emissions_report.pdf. Page 32, Table 5-3.

benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- Non-Embedded SO_2 Reduction Benefit ($/yr) = ElectricEnergySavings kWh/yr * SO_2EmissionsRate ton/kWh * (NonEmbeddedSO_2Value $/ton - Embedded$SO_2$Value $/ton) * TechnologyCoincidence * EfficiencyLoss (1 + %Losses) * (1 + %Inflation)^(year-2015)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- SO_2EmissionsRate (ton/kWh) = 0.02 lb SO_2/MWh * 1/1,000 MWh/kWh ÷ 2,000 lb/ton (ISO-NE 2021,[34] Table 5-3, 2019 Time-Weighted LMU Marginal Emissions Rates-All LMUs, SO_2 "Annual Average (All Hours)")
- NonEmbeddedSO_2Value ($/ton) = $69,000-$79,500/ton (US EPA 2019, Tables 5-10, average of SO_2 from "Electricity Generation Units", 2015 dollars)
- EmbeddedSO_2Value ($/ton) = $0.02/ton (AESC 2021, Page 107, SO_2 "2021$")[35]
- TechnologyCoincidence = Coincidence Factor based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss", "ISO default")
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

Note that the AESC 2021 Study does not include estimates for avoided SO_2 emissions costs due to the Study's assertion that most of the available emission data is quite old and the impacts are very small.[36]

3.11 Economic Development Benefits

The Docket 4600 Framework includes consideration of societal economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modelling. Therefore, economic development impacts (e.g., economic growth, job creation) can be quantified using the Regional Economic Models, Inc. (REMI) model of the Rhode Island economy, which estimates the increased economic activity resulting from investments. The overall societal impact is measured by net Rhode Island gross domestic product (GDP), which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms.

RI Energy agrees with Docket 4600 that economic development benefits are important. However, including these benefits in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits, which can discredit other more precise components of the

[34] "2019 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., March 2021, https://www.iso-ne.com/static-assets/documents/2021/03/2019_air_emissions_report.pdf. Page32.

[35] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf . Page 107.

[36] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf Page 56.

BCA. Additionally, because the benefits can be large, they create a "masking" effect. For these reasons, the RI NWA BCA Model did not consider economic development benefits in its BCA.

3.12 Contract/Solution Costs

The contract or solution cost is the direct cost for the NWA. This could be a payment schedule to a third party or for paid customer participation (e.g., targeted energy efficiency or demand response). These cost schedules are typically based on an annual, semi-annual, or monthly cadence. Additionally, these cost schedules may involve an annual escalator. In cases with a known, irregular cost schedule these costs can be entered manually in their respective years.

3.13 Administrative Costs

Administrative costs are related to the ongoing support of the NWA. Administrative costs can include evaluation, measurement and verification (EM&V) costs, ongoing communications and information technology fees, or additional costs related to the post-implementation costs to keep the NWA viable. For each solution an annual expected administrative cost will be applied. In cases with a known, irregular admin cost schedule these costs can be entered manually in their respective years.

3.14 Utility Interconnection Costs

The interconnection cost is the cost for physically and digitally linking the solution to the electric system. This can include upgrading the wires (e.g., with a battery storage or solar solution) or a telecommunications upgrade. Interconnection costs will be determined on a case-by-case basis regarding the specific system need and its respective targeted NWA. This cost will generally be a capital expenditure, initially borne by the utility, prior to the commercially viable date of the NWA solution.

4. Benefit-Cost Calculations

The RI NWA BCA Model is a comparison tool to be utilized to analyze multiple solutions with respective technologies to assess their cost-effectiveness. Currently four technology types are assessed: Battery Storage, Solar, Demand Response, and Energy Efficiency. The RI NWA BCA Model will be expanded as new technologies or solutions evolve. The RI NWA BCA Model is structured to allow for any given solution to utilize any, all, or a combination of these technologies on a per solution basis.

As prescribed by the Standards, the RI NWA BCA Model uses a "discount rate that appropriately reflects the risks of the investment". The Company maintains that the most reasonable rate at which to discount future year costs and benefits is the Company's after-tax Weighted Average Cost of Capital (WACC) (currently 6.97%)[37] since the NWA investments are utility investments, and after-tax WACC is the Company's effective discount rate.

The total benefits will equal the sum of the net present value (NPV) of each annual benefit component:

- [Electric Energy Benefits + Compliance Benefits + DRIPE Benefits + Electric Generation Capacity Benefits + Electric Transmission Capacity Benefits + Electric Distribution Capacity Benefits + Electric Transmission Infrastructure Site Specific + Natural Gas Benefits + Fuel Benefits + Water & Sewer Benefits + Value of Improved Reliability + Non-Energy Impacts + Non-Embedded GHG Reduction Benefits + Non-Embedded NOx Reduction Benefits + Non-Embedded SO_2 Reduction Benefits + Economic Development Benefits]

The total costs will equal the sum of the NPV of each annual cost component:

- [Contract/Participant Costs + Program Administrative Costs + Utility Interconnection Costs]

The RI Test benefit-cost ratio (BCR) will then equal:

- Total NPV Benefits ÷ Total NPV Costs

The BCA can then financially compare multiple solutions, regardless of technology type.

The NWA investment will be considered cost-effective if the BCR for the resource is greater than 1.0.

[37] "Docket No. 4770." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 29 Nov. 2017, www.ripuc.ri.gov/eventsactions/docket/4770page.html.

5. Appendices

Appendix 1	AESC 2021 Materials Source Reference
Appendix 2	Table of Terms

Appendix 1: AESC 2021 Materials Source Reference

Please refer to the following citation for the Appendix B data tables of the AESC 2021 Study materials.

> "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials.

Appendix 2: Table of Terms

Term	Definition
AESC	Avoided Energy Supply Components
AESC 2021 Study	Avoided Energy Supply Components in New England: 2021 Report
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
Capex	Capital expenditure
CO_2	Carbon dioxide
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effect(s)
EE	Energy Efficiency
EE Plan	Energy Efficiency Program Plan
EEP	Energy Efficiency Program
EERMC	Energy Efficiency and Resource Management Council
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
ESS	Energy Storage System
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHG	Greenhouse gas
ISO	Independent Systems Operator
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
LCP	Least-Cost Procurement
LCP Standards	Least-Cost Procurement Standards
LMU	Locational Marginal Unit
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Energy Reliability Corporation
NOx	Nitrogen oxides (NO, NO_2)

Term	Definition
NPV	Net Present Value
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
Opex	Operational expenditure
PM	Particulate Matter
PTF	Pool Transmission Facilities
PTL	Pool Transmission Losses
PUC	Public Utilities Commission
RD&D	Research, Design, and Development
REC	Renewable Energy Credit
REMI	Regional Economic Models, Inc.
RGGI	Regional Greenhouse Gas Initiative
RI	Rhode Island
RI NWA BCA Model	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model
RI NWA BCA TRM	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Technical Reference Manual
RI Test	Rhode Island Benefit-Cost Test
ROP	Rest of Pool
RPS	Renewable Portfolio Standards
SO_2	Sulfur dioxide
T&D	Transmission and Distribution
TRC Test	Total Resource Cost Test
TRM	Technical Reference Manual
US	United States of America
WACC	Weighted Average Cost of Capital
WCMA	West/Central Massachusetts
WRP	Wholesale Risk Premium

Appendix 8. Gas System Reliability Procurement Benefit-Cost Assessment Model

See attachment. No proposed changes.

The Company provided the Excel version of Appendix 8.

Appendix 9. Gas System Reliability Procurement Technical Reference Manual

See attachment. No proposed changes.

Rhode Island Energy's Technical Reference Manual

for the

Benefit-Cost Analysis

of

Non-Pipeline Alternatives

in

Rhode Island

For use by and prepared by

The Narragansett Electric Company
d/b/a Rhode Island Energy

Table of Contents

NATIONAL GRID's RHODE ISLAND NON-PIPES ALTERNATIVES BENEFIT-COST ANALYSIS TECHNICAL REFERENCE MANUAL

1. Introduction

National Grid's[1] Rhode Island Non-Pipeline Alternatives Benefit-Cost Analysis Technical Reference Manual (RI NPA BCA TRM) details how the Company assesses cost-effectiveness of Non-Pipeline Alternative (NPA) opportunities planned in Rhode Island through the Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Model (RI NPA BCA Model). This cost-effective assessment is in alignment with the Rhode Island Benefit Cost Test (RI Test) as detailed in the Docket 4600 Benefit-Cost Framework[2] and in accordance with Sections 1.3(B) and 1.3(C) of the Least-Cost Procurement Standards (LCP Standards) as detailed in Docket 5015[3], with both dockets respectively approved by the Rhode Island Public Utilities Commission (PUC)[4]. Although the LCP Standards were originally developed for the Company's Energy Efficiency (EE) program, the same principles have been applied to other benefit-cost analyses (BCA) conducted by the Company at the request of the PUC, including the RI NPA BCA Model.

The following RI NPA BCA Model approach was based on the LCP Standards:

I. Assess the cost-effectiveness of the NPA portfolio per a benefit-cost test that builds on the Total Resource Cost Test (TRC Test) approved by the Public Utilities Commission (PUC) in Docket 4443[5], but that more fully reflects the policy objectives of the State with regard to energy, its costs, benefits, and environmental and societal impacts. Based on the Company's EE Program Plans, in consultation with the EERMC, it was determined that these benefits should include resource impacts, non-energy impacts, distribution system impacts, economic development impacts, and the value of greenhouse gas (GHG) reductions, as described below.

II. Apply the following principles when developing the RI Test:

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

---

[1] The Narragansett Electric Company d/b/a Rhode Island Energy (Rhode Island Energy or Company).

[2] "Docket No. 4600 and Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2 Nov. 2018, www.ripuc.ri.gov/eventsactions/docket/4600page.html.

[3] "Least Cost Procurement Standards." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 21 Aug. 2020, http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf.

[4] "RIPUC." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island, www.ripuc.ri.gov/.

[5] "Docket No. 4443." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 17 Sept. 2013, www.ripuc.ri.gov/eventsactions/docket/4443page.html.

b. **Energy Policy Goals.** Rhode Island's cost-effectiveness test should account for its applicable policy goals, as articulated in legislation (e.g., Resilient Rhode Island Act[6]), PUC orders, regulations, guidelines, and other policy directives.

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

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

e. **Forward Looking**. Analysis of the impacts of the investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of the NPA investment with those that would occur absent the investments (i.e., "Reference Case"). Sunk costs and benefits are not relevant to a cost-effectiveness analysis.

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

III. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of carbon dioxide (CO_2) mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative (RGGI)[7]. The RI Test shall also include any other utility system costs associated with reasonably anticipated future greenhouse gas reduction requirements at the state, regional, or federal level for both electric and gas programs. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above (e.g., non-embedded or societal CO_2 costs). The RI Test may also include the costs and benefits of other emissions and their generation or reduction through LCP (e.g., nitrogen oxides (NOx), sulfur dioxide (SO_2)).

IV. Benefits and costs that are projected to occur over the project life of the individual NPA projects shall be stated in present value terms in the RI Test calculation using a discount rate that appropriately reflects the risks and opportunity cost of the investment.

[6] "Resilient Rhode Island Act of 2014 - Climate Change Coordinating Council." *Chapter 42-6.2*, State of Rhode Island and Providence Plantations, 2014, http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM.

[7] "State Statutes & Regulations - Rhode Island." *The Regional Greenhouse Gas Initiative*, RGGI, Inc., www.rggi.org/program-overview-and-design/state-regulations.

2. Overview of the Rhode Island Test

The RI Test compares the present value of a stream of **total benefits** to the **total costs** of the investment, **over the life** of that investment necessary to implement and realize the **net benefits**. The RI Test captures the value produced by the investment installed over the useful life of the investment. The investment life is based on the individual NPA contract timeframe and thus is expected to change on a per project basis.

The benefits calculated in the RI Test are primarily avoided resource (e.g., natural gas energy) supply and distribution costs, valued at marginal cost for the periods when there is a load reduction; and the monetized value of non-resource savings including avoided costs compared to a Reference Case (e.g., avoided utility capital and operations and maintenance (O&M) costs). The costs calculated in the RI Test are those borne by both the utility and by participants plus the increase in supply costs for any period when load is increased. All capital expenditure (CAPEX) (e.g., equipment, installation) and operational expenditure (OPEX) (e.g., evaluation and administration) are included.

All savings included in the value calculations are net savings. The expected net savings are typically an engineering estimate of savings modified to reflect the actual realization of savings based on evaluation studies, when available. The expected net savings also reflect market effects due to the program (*e.g.*, Demand Reduction Induced Price Effects (DRIPE)).

In accordance with Section 1.3.B of the revised Standards, Rhode Island Energy adheres to the RI Test for all NPA investment proposals. Rhode Island Energy has developed the RI NPA BCA Model, which is a derivative of the RI Test and utilizes the same Docket 4600 Benefit-Cost Framework, to more accurately assess NPA opportunities benefits and costs. The benefit categories and formulas in the RI NPA BCA Model are detailed in Section 3.

3. Description of Program Benefits and Costs

Table 1 summarizes the benefits and costs included in the RI Test and how they are treated in the Company's NPA BCA. Note that an "X" indicates that the category is quantified while an "O" indicates the category is unquantified, as applicable for RI NPAs. The "Docket 4600 Category" column in the table below references the categories and their respective details listed within Appendix A of Docket 4600.[8]

Table 1. Summary of RI Test Benefits and Costs and Treatment

<table>
<tr><th>RI Test Category</th><th>Docket 4600 Category</th><th>NPA</th><th>Notes</th></tr>
<tr><td rowspan="4">Electric Energy Benefits</td><td>Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power System Level)</td><td>O</td><td rowspan="4">(1)</td></tr>
<tr><td>Retail Supplier Risk Premium (Power System Level)</td><td>O</td></tr>
<tr><td>Criteria Air Pollutant and Other</td><td>O</td></tr>
<tr><td>Distribution System Performance (Power System Level)</td><td>O</td></tr>
<tr><td rowspan="3">Renewable Portfolio Standards (RPS) and Clean Energy Policies Compliance Benefits</td><td>REC Value (Power System Level)</td><td>O</td><td rowspan="3">(1)</td></tr>
<tr><td>GHG Compliance Costs (Power System Level)</td><td>O</td></tr>
<tr><td>Environmental Externality Costs (Power System Level)</td><td>O</td></tr>
<tr><td>Demand Reduction Induced Price Effects</td><td>Energy DRIPE (Power System Level)</td><td>X</td><td></td></tr>
<tr><td>Electric Generation Capacity Benefits</td><td>Forward Commitment Capacity Value (Power System Level)</td><td>O</td><td>(1)</td></tr>
<tr><td rowspan="2">Electric Transmission Capacity Benefits</td><td>Electric Transmission Capacity Value (Power System Level)</td><td>O</td><td rowspan="2">(1)</td></tr>
<tr><td>Electric Transmission Infrastructure Costs for Site-Specific Resources</td><td>O</td></tr>
<tr><td>Electric Distribution Capacity Benefits</td><td>Distribution Capacity Costs (Power System Level)</td><td>O</td><td>(1)</td></tr>
<tr><td>Natural Gas Benefits</td><td rowspan="3">Participant non-energy benefits: oil, gas, water, wastewater (Customer Level)</td><td>X</td><td></td></tr>
<tr><td>Delivered Fuel Benefits</td><td>X</td><td></td></tr>
<tr><td>Water and Sewer Benefits</td><td>O</td><td>(2)</td></tr>
<tr><td>Value of Improved Reliability</td><td>Distribution System and Customer Reliability/Resilience Impacts (Power System Level)</td><td>X</td><td></td></tr>
<tr><td rowspan="3">Non-Energy Impacts</td><td>Distribution Delivery Costs (Power System Level)</td><td>O</td><td rowspan="3">(3)</td></tr>
<tr><td>Distribution system safety loss/gain (Power System Level)</td><td>O</td></tr>
<tr><td>Customer empowerment and choice (Customer Level)</td><td>O</td></tr>
</table>

[8] "Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 3 Aug. 2017, www.ripuc.ri.gov/eventsactions/docket/4600A-PUC-GuidanceDocument-Notice_8-3-17.pdf. Appendix A.

RI Test Category	Docket 4600 Category	NPA	Notes
	Utility low income (Power System Level)	O	
	Non-participant rate and bill impacts (Customer Level)	O	
Non-Embedded GHG Reduction Benefits	GHG Externality Cost (Societal Level)	X	
Non-Embedded NOx Reduction Benefits	Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)	X	
Non-Embedded SO_2 Reduction Benefits	Public Health (Societal Level)	X	
Economic Development Benefits	Non-energy benefits: Economic Development (Societal Level)	O	(4)
Utility Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or Distributed Energy Resources costs	X	
Participant Costs	Program participant / prosumer benefits / costs (Customer Level)	X	

Notes
An “X” indicates that the category is quantified while an “O” indicates the category is unquantified, as applicable for RI NPAs in the SRP program.
(1) Electric-specific benefits/cost categories are captured in the RI NWA BCA Model and are not applicable to the RI NPA BCA Model.
(2) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e., NWAs).
(3) Currently do not have data to claim benefits for a targeted need case.
(4) Sensitivity analysis is currently under development. This benefit is negligible unless sensitivity analysis determines otherwise.

The following additional Docket 4600 Benefit Categories require further analysis to determine the appropriate methodology and magnitude of quantitative or qualitative impacts:

- Low-income participant benefits (Customer Level)
- Forward commitment avoided ancillary services value (Power System Level)
- Net Risk Benefits to Utility System Operations from Distributed Energy Resource (DER) Flexibility & Diversity (Power System Level)
- Option value of individual resources (Power System Level)
- Investment under uncertainty: real options value (Power System Level)
- Innovation and learning by doing (Power System Level)
- Conservation and community benefits (Societal Level)
- Innovation and knowledge spillover - related to demo projects and other Research, Design, and Development (RD&D) (Societal Level)
- Societal low-income impacts (Societal Level)
- National security and US international influence (Societal Level)

All quantified NPA benefits are directly associated with the development of non-pipes compared to a Reference Case with no NPA options. The source for many of the avoided cost value components is the "Avoided Energy Supply Components in New England: 2021 Report" (AESC 2021 Study) prepared by Synapse Energy Economics for AESC 2021 Study Group in May, 2021.[9] This report was sponsored by the electric and gas EE program administrators of Rhode Island Energy in New England and is designed to be used for cost-effectiveness screening in 2019 through 2021.

The AESC Study determines projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels, as well as avoided environmental compliance costs resulting from EE and other conservation programs. The AESC study is prepared every three years for the AESC Study Group, which is comprised of the Program Administrators as detailed in the AESC Study, as well as utilities throughout New England and other interested non-utility parties.

The AESC Study provides projections of avoided costs of energy in each New England state for a hypothetical future in which a myriad of EE and DER opportunities exist. The NPA BCA utilizes RI specific values where available. In some cases where RI specific values are not available, Southern New England values are used.

The RI NPA BCA methodology is technology agnostic and should be broadly applicable to all anticipated project and portfolio types, with some adjustments as necessary. Specific availability of a technology during the specified system need time may differ. This technology coincidence factor is based upon the association between the distribution system, supply, and peak demand for the specified NPA need. These generalized values are subject to change.

3.1 Electric Energy Benefits

Electric energy benefits due to NPA implementation can be a result of reduced energy usage (e.g., targeted EE or DR), a shift of usage from peak to off-peak (e.g., battery storage), or energy generation (e.g., solar). The resulting avoided electric energy costs are appropriate benefits for inclusion but are calculated and considered by using the RI NWA BCA Model. Electric energy benefits are valued using the avoided electric energy costs developed in the AESC 2021 Study, Appendix B.[10]

Electrification of end-uses is an NPA technology. Electric appliances and heating equipment can be used as an alternative to natural gas to reduce natural gas demand. To represent an increase in electric demand, the electric energy savings value should be negative.

Additional context on this benefit is included within the RI NWA Technical Reference Manual as detailed in Appendix 5 of the 2020 SRP Year-End Report as found in Docket No. 5080.[11]

---

[9] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[10] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix B*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[11] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

3.2 RPS and Clean Energy Policy Compliance Benefits

This benefit category captures the value of avoided embedded CO_2 and SO_2 costs separately from the "Environmental and Public Health Benefits" category and is applicable electric energy benefits only. These RPS and Clean Energy Policy compliance benefits due to NPAs are the results of the reduced energy usage as described in Section 3.1. Additional context on this benefit is included within the RI NWA Technical Reference Manual as detailed in Appendix 5 of the 2020 SRP Year-End Report as found in Docket No. 5080.[12]

3.3 Demand Reduction Induced Price Effects

DRIPE is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to reduced demand from electric system investments. These gas system investments can include NPAs. These investments avoid both marginal energy production and capital investments, but also lead to structural changes in the market due to lower demand. Over a period of time, the market adjusts to lower demand, but until that time the reduced demand leads to a reduction in the market price of the energy commodity. When this price effect is a result of NPAs, it is appropriate to include the impact in the RI NPA BCA Model.

DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms over all the MMBtu transacted across the market. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Gas Supply and Cross DRIPE values developed for the AESC 2021 Study are used in the RI NPA BCA Model. Gas Supply DRIPE is the value of reduced natural gas demand on gas commodity prices. This has a Zone-on-Zone component differentiated by state and Zone-on-Rest-of-Region DRIPE that accounts for reductions in one zone impact on New England customers. Since RI has its own zone this calculator uses those specific Zone DRIPE benefits. 3.1AESC also provides annual Cross DRIPE values to account for electricity price effects caused by a change in natural gas pricing. Each technology then has a coincidence and rating factor that is applied based on its system need.

Loss factors are applied to the Gas Supply and Cross DRIPE values to account for lost and unaccounted for gas (LAUF) from the point of delivery to the customer's facility.

The dollar value of annual benefits is therefore calculated as:

- GasSupplyDRIPE Benefit ($/yr) = NaturalGasSavings MMBtu/yr * GasSupplyDRIPE $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)
- CrossDRIPE Benefit ($/yr) = NaturalGasSavings MMBtu/yr * CrossDRIPE $/MMBtu * TechnologyCoincidence * TechnologyDerate* (1 + %LAUF) * (1 + %Inflation)^(year-2021)

[12] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

Where:

- NaturalGasSavings(MMBtu/yr) = Estimated annual natural gas savings based on Engineering models
- GasSupplyDRIPE ($/MMBtu) = Projected annual values (AESC 2021, Appendix C, "Zone-on-Zone Gas Supply DRIPE")
- CrossDRIPE ($/MMBtu) = Projected annual values (AESC 2021, Appendix C, "Zone-on-Zone G-E cross DRIPE")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (Rhode Island Energy RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)[13]
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.4 Electric Capacity Benefits

Electric capacity benefits due to NPAs are a result of load reductions or increases in electric demand as result of the NPA implementation (i.e., electrification). The resulting electric capacity benefits are appropriate for inclusion but are calculated and considered by using the RI NWA BCA Model. Electric energy benefits are valued using the avoided electric capacity costs developed in the AESC 2021 Study, Appendix B.[14] Additional context on this benefit is included within the RI NWA Technical Reference Manual as detailed in Appendix 5 of the 2020 SRP Year-End Report as found in Docket No. 5080.[15]

3.5 Natural Gas Benefits

An avoided resource benefit is produced when an NPA reduces natural gas usage. Natural gas energy and capacity benefits are considered and included in the RI NPA BCA Model calculations.

3.5.1 Natural Gas Energy Benefits

Natural gas energy benefits due to NPA implementation can be a result of reduced energy usage (e.g., EE) or the elimination of natural gas usage (e.g., electrification). The resulting avoided natural gas energy costs are appropriate benefits for inclusion in the RI NPA BCA Model. Natural gas energy benefits are valued by end use and developed in the AESC 2021 Study, Appendix C.[11]

Avoided costs may be viewed as a proxy for market costs. However, avoided costs may be different from wholesale market spot costs because avoided costs are based on simulation of market conditions, as opposed to real-time conditions. They may be different from standard offer commodity costs because of time lags and differing opinions on certain key assumptions, such as short-term fuel costs.

---

[13] "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data." *PHMSA*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[14] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix B*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[15] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

In the RI NPA BCA benefits calculation, energy savings are grossed up using a lost and unaccounted for gas (LAUF) factor, because a reduction in energy use at the end user means that amount of energy does not have to generated, plus the extra generation that is needed to cover the losses that occur in the delivery.

AESC's avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the local distribution company (LDC) and (2) the avoided cost of delivering gas on the LDC system. The retail costs of natural gas energy in the AESC 2021 Study are provided by end-use categories. Net energy savings are apportioned into these categories in the value calculation. The end-use categories are defined as follows:

- Non-Heating: Year-round end-uses generally constant gas usage throughout the year
- Hot Water: Year-round hot water end-uses generally constant gas usage throughout the year
- Heating: Space heating end-uses in which gas use is high during winter months
- All: Inclusive of heating and non-heating gas usage throughout the year

In cases where an energy use transfer occurs, energy reductions and increases could occur across fuel types (e.g., demand response). Each solution is considered by end-use category and then added together resulting in a net monetized energy reduction value. Furthermore, a derate factor is applied to solutions where customer behavior plays a role in the demand reduction achieved. This factor is used to scale the projected demand reduction to ensure the benefits of the solution are being characterized appropriately.

Natural gas energy savings created through NPAs are valued using the avoided cost of gas to retail customers by end-use from the 2021 AESC, Appendix C.[16] The values are then grossed up to account for distribution losses. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Natural gas energy savings are specific to a measure and the end-use of natural gas they impact.

The dollar value of annual benefits is therefore calculated as:

- Natural Gas Energy Benefit ($/yr) = NaturalGasEnergySavings MMBtu/yr * $\text{RetailCost}_{\text{EndUse}}$ $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas energy savings based on Engineering models
- $\text{RetailCost}_{\text{EndUse}}$ ($/MMBtu) = Retail value to customers by end-use (AESC 2021, Appendix C, "Avoided cost of gas to retail customers for Southern New England (SNE) assuming no avoidable retail margin")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type

[16] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix C*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (Rhode Island Energy, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.5.2 Natural Gas Capacity Benefits

At the supply level, natural gas supply capacity benefits due to NPAs are a result of load reductions at winter peak. At the distribution and supply infrastructure site-specific level, natural gas capacity benefits are a result of the deferred system upgrade. This value is an avoided cost based on a time-deferred expected project cost of the system upgrade.

3.5.2.1 Natural Gas Supply Capacity Benefits

When additional natural gas capacity does not have to be procured because of NPAs, an avoided natural gas capacity benefit is created. An LDC builds its natural gas system and procures natural gas supply to maintain system pressures and conditions during peak demand. In New England, the system peak occurs in the winter during the coldest days of the year as natural gas is widely used for space heating today. Supply capacity benefits accrue when winter peak demand is reduced. To convert annual natural gas demand to peak load demand, a factor of 1.25% is used. This value is a company assumption derived from distribution design.

Supply capacity savings created through NPAs are valued using the avoided natural gas costs from the 2021 AESC, Appendix C.[17] The values are then grossed up to account for distribution losses. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Capacity savings are specific to a measure and costing period based on how the program is designed. The highest monetary value and benefit is produced by a measure that can deliver during the peak times, which is in the winter during the coldest days of the year.

Avoided natural gas costs in the AESC 2021 Study are provided in six different costing periods. Net energy savings are apportioned into these periods in the value calculation. The six costing periods throughout the year are defined as follows:

- Highest 10 Days: Gas requirements that only occur on the coldest 10 days of the year
- Highest 30 Days: Gas requirements that only occur on the coldest 30 days of the year
- Highest 90 Days: Gas requirements that occur only during the coldest 90 days of the year
- Winter: November through March
- Winter/Shoulder: All months except June through August
- Baseload: Load that is constant throughout the year, all months

NPA system needs have a targeted demand reduction during a specific costing period. Each system need will therefore have a specific cost period to focus a solution to deliver demand reduction during specific times of the year. Natural gas supply capacity savings for NPAs are allocated to specific times of the year

[17] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix C*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

and multiplied by the appropriate avoided capacity value. Generally, the system need is occurring during the winter season when natural gas demand is the highest.

The dollar value of annual benefits is therefore calculated as:

- Natural Gas Supply Capacity Benefit ($/yr) = CumulativeAnnualPeakSavings MMBtu * $\text{CapacityValue}_{\text{CostPeriod}}$ $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 +%LAUF) * (1 + %Inflation)^(year-2021)

Where:

- CumulativeAnnualPeakSavings (MMBtu) = Estimated peak natural gas capacity savings based on Engineering models
- $\text{CapacityValue}_{\text{CostPeriod}}$ ($/MMBtu) = Projected annual value associated with a specific costing period (AESC 2021, Appendix C, "Avoided natural gas costs by costs period – Southern New England")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (Rhode Island Energy, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.5.2.2 Natural Gas Distribution Capacity Benefits

Distribution Capacity benefit is based on the direct deferred distribution infrastructure due to the implementation of the NPA. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NPA.

3.5.2.3 Natural Gas Supply Infrastructure Site-Specific Benefits

Supply Infrastructure Site-Specific benefit is based on the direct deferred supply infrastructure due to the implementation of the NPA. This benefit category applies to supply infrastructure located on the distribution system that would be installed and operated by an LDC. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NPA. This value will typically be null for demand-side NPAs.

3.6 Delivered Fuel Benefits

Customers use a variety of fuels and energy sources to meet their energy needs. To consider fuels other than natural gas, the demand for alternative fuels is included in the RI NPA BCA models. Fuel oil delivered fuel is currently included and the RI NPA BCA model can be expanded to include additional fuel types as appropriate.

3.6.1 Fuel Oil Delivered Fuel Benefits

Fuel oil is often used as an alternative fuel to natural gas to reduce natural gas peak demand during peak times. Fuel oil when used in place of natural gas generates a fuel oil delivered fuel value. To represent an increase in fuel oil usage, the fuel oil savings value should be negative.

Fuel oil delivered fuel benefits created through NPAs are valued using the avoided costs of fuels from the 2021 AESC, Appendix D.[18] Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Furthermore, a derate factor is applied to solutions where customer behavior plays a role in the demand reduction achieved. This factor is used to scale the projected increase in alternative fuel consumption.

The dollar value of annual benefits is therefore calculated as:

- Fuel Oil Energy Benefit ($/yr) = FuelOilEnergySavings MMBtu/yr * $\text{RetailCost}_{\text{DistFuelOil}}$ $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %Inflation)^(year-2021)

Where:

- FuelOilEnergySavings (MMBtu/yr) = Estimated annual fuel oil energy savings based on the need to offset natural gas use
- $\text{RetailCost}_{\text{DistFuelOil}}$ ($/MMBtu) = Retail value to customers by sector (AESC 2021, Appendix D, "Avoided cost of petroleum fuels and other fuels by sector")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.7 Water and Sewer Benefits

An avoided resource benefit is produced when a project, in which customers have invested to save fuel or electricity, also reduces water consumption. Examples of reduced water consumption can include a cooling tower project that reduces makeup water usage or need. Water and sewer benefits are negligible for NPAs, so they are not included in the RI NPA BCA Model calculations.

3.8 Value of Improved Reliability

Due to the site-specific nature of these solutions, a reliability benefit should also be localized. The reliability benefit is currently difficult to quantify due to the new nature of the technologies that NPAs typically utilize. This benefit will be developed and applied as more projects are implemented and technology-specific reliability values are determined.

3.9 Non-Energy Impacts

Non-Energy Impacts (NEIs) can be produced as a direct result of NPA investments and are therefore appropriate for inclusion in the RI NPA BCA Model. Non-energy impacts may include but are not limited to: labor, material, facility use, health and safety, materials handling, national security, property values, and transportation. For income-eligible measures, NEIs also include the impacts of lower energy bills, such as reduced arrearages or avoided utility shut-off costs. The Company plans to conduct future bill

[18] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix D*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

impact studies should non-participant rate and bill impacts be included in future. These benefits are currently seen to be negligible for NPAs.

3.10 Environmental and Public Health Impacts

Environmental benefits due to NPAs are a result of reduced energy use from the implemented solution. The resulting avoided environmental costs are appropriate benefits for inclusion in the RI NPA BCA Model. Reduction in the use of natural gas procured provides environmental benefits to Rhode Island and the region, including reduced greenhouse gas emissions and improved air quality. This BCA does account for net environmental impacts. Thus, in cases where the reduction in natural gas would be offset by increases in electricity or alternative fuel sources, a net environmental impact will be derived.

3.10.1 Non-Embedded Greenhouse Gas Reduction Benefits

Carbon dioxide and other GHG emissions come from a variety of sources, including the combustion of fossil fuels like natural gas, coal, gasoline, and diesel. Increase in atmospheric CO_2 concentrations contributes to an increase in global average temperature, which results in market damages, such as changes in net agricultural productivity, energy use, and property damage from increased flood risk, as well as nonmarket damages, such as those to human health and to the services that natural ecosystems provide to society.[19]

According to the AESC 2021 Study, the cost of GHG emissions reductions can be determined based on estimating either carbon damage costs or marginal abatement costs. Damage costs in the AESC are sourced from the December 2020 SCC Guidance published by the State of New York. This guidance recommended a 15 year levelized price of $128 per short ton. Due to the many uncertainties in climate damage cost estimates, the AESC study concluded that the marginal abatement cost method should be used instead. This method asserts that the value of damage avoided, at the margin, must be at least as great as the cost of the most expensive abatement technology used in a comprehensive strategy for emission reduction.[20]

The AESC 2021 Study developed three approaches for calculating the non-embedded cost of carbon based on marginal abatement costs. The first approach is an estimate for the global marginal carbon abatement cost based on carbon capture and sequestration technology, which yields a value of $92 per short ton of CO_2 equivalent and is lower than the prior AESC 2018 Study[21] value used. The second approach is based on a New England specific marginal abatement cost, where it is assumed that the marginal abatement technology is offshore wind. The third approach assumes a New England specific cost derived from multiple sectors, not just electric.

The New England specific marginal abatement costs assume a $125 per short ton of CO2 emissions. This is based on the future cost trajectories of offshore wind facilities along the east coast of the United States.

---

[19] National Academies of Sciences, Engineering, and Medicine 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651.

[20] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Pages 171 to 182.

[21] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/project/aesc-2018-materials

This aligns with New York Department of Environmental Conservation's 2020 valuation of $125 per ton. This value is used in this BCA model.

The AESC 2021 uses an assumed 117 pounds of CO2 per MMBtu for natural gas. This is derived from the U.S. Energy Information Administration's assumption of about 117 lbs/MMBtu across all sectors of natural gas use. The AESC 2021 also includes assumptions of other fuel emissions including fuel oil, gasoline, and electricity. In cases where the solution would have alternate fuel increases in the solution a net greenhouse gas reduction will be utilized.

Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Loss factors are applied to the natural gas supply to account for local lost and unaccounted for gas to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- GHG Reduction Benefit ($/yr) = NaturalGasEnergySavings MMBtu/yr * GHG Costs $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas energy savings based on Engineering models
- GHG Cost ($/MMBtu) = Cost of GHG emissions (AESC 2021, Table 159, "Marginal emission rates for non-electric sectors")[22]
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (Rhode Island Energy, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.10.2 Non-Embedded NOx Reduction Benefits

Nitrogen oxide (NOx) emissions come from a variety of sources including heavy duty vehicles, industrial processes, and the combustion of natural gas. NOx contributes to the formation of fine particle matter (PM) and ground-level ozone that are associated with adverse health effects including heart and lung diseases, increased airways resistance, which can aggravate asthma and other underlying health issues, and respiratory tract infections. In addition to known health impacts, PM pollution and ozone are also likely to contribute to negative climate impacts.[23]

[22] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Table 159

[23] "Our Nation's Air: Status and Trends through 2019." *Our Nation's Air: Trends Report*, United States Environmental Protection Agency, 2020, https://gispub.epa.gov/air/trendsreport/2020.

The AESC 2021 Study estimates avoided NOx emissions costs utilizing a continental U.S. average, non-embedded NOx emission wholesale cost of $14,700 per ton of NOx (2021 dollars).[24] This translates to a $0.71 per MMBtu in 2021. The RI NPA BCA model utilizes this AESC 2021.

Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Loss factors are applied to the natural gas supply to account for local lost and unaccounted for gas to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- NOx Reduction Benefit($/yr) = NaturalGasEnergySavings MMBtu/yr * NOxCosts $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas energy savings based on Engineering models
- NOxCosts = Projected annual values for NOx emissions (AESC 2021, Table 159, "Marginal emission rates for non-electric sectors")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (Rhode Island Energy, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.10.3 Non-Embedded SO_2 Reduction Benefits

Sulfur dioxide (SO_2) emissions come from a variety of sources including industrial processes and the combustion of coal (especially high-sulfur coal) and fuel oil for electricity generation and heating. SO_2 contributes to the formation of fine PM that are associated with adverse health effects including heart and lunch diseases and increased airways resistance, which can aggravate asthma and other underlying health issues. In addition to known health impacts, PM pollution is also likely to contribute to negative climate impacts.[25]

In February, 2018, the US EPA published a Technical Support Document for estimating the benefit of reducing PM2.5 precursors from 17 sectors.[26] The EPA document estimates national average values for

---

[24] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Page 183

[25] "Our Nation's Air: Status and Trends through 2019." *Our Nation's Air: Trends Report*, United States Environmental Protection Agency, 2020, https://gispub.epa.gov/air/trendsreport/2020.

[26] "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors (February 2018)." *US EPA Benefits Mapping and Analysis Program (BenMAP)*, United States Environmental Protection Agency, Feb. 2018, www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-17-sectors.

mortality and morbidity per ton of directly-emitted SO_2 reduced for 2016, 2020, 2025, and 2030 based on the results from two other studies.[27,28] Using the average of the results from the two studies, the RI NWA BCA Model estimates the SO_2 emissions cost to be $69,000 per ton of SO_2 in 2020 (2015 dollars) increasing to $79,500 per ton of SO_2 in 2030 (2015 dollars). The EPA released its Natural Gas Combustion report in 2020.[29] This report stated that SO_2 emissions from natural gas typically has extremely low sulfur levels of 2,000 grains per million cubic feet (MCF). However, sulfur-containing odorants are added to natural gas leading to small amounts of SO_2 emissions. This results in a small SOx impact in natural gas of approximately 0.0006 lbs/MMBtu and a $0.02 impact per MMBtu. For cases where the solution includes distillate fuel used as a natural gas replacement the net emissions savings will include emissions from the distillate fuel.

Loss factors are applied to the emissions factor to account for lost and unaccounted for gas from supply to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- SO_2 Reduction Benefit ($/yr) = NaturalGasEnergySavings MMBtu/yr * SO_2EmissionsRate lb/MMBtu * SO_2Value $/ton* TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2015)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas savings based on Engineering models
- SO_2EmissionsRate (lb/MMBtu) = 0.00059 lb SO_2/MMBtu (EPA 1.4 Natural Gas Combustion, Table 1.4-2 "Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion" SO_2Value ($/ton) = $69,000-$79,500/ton (US EPA 2019, Tables 5-10, average of SO_2 from "Electricity Generation Units", 2015 dollars)
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (Rhode Island Energy, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

---

[27] Krewski, Daniel, et al. "Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality." Health Effects Institute, Health Effects Institute, 26 May 2021, https://www.healtheffects.org/publication/extended-follow-and-spatial-analysis-american-cancer-society-study-linking-particulate.

[28] Lepeule, Johanna, et al. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009." National Institute of Environmental Health Sciences, U.S. Department of Health and Human Services, 1 July 2012, https://ehp.niehs.nih.gov/doi/10.1289/ehp.1104660.

[29] "1.4 Natural Gas Combustion Final Section - Supplement D, July 1998." *EPA*, Environmental Protection Agency, https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.

Note that the AESC 2021 Study does not include estimates for avoided SO_2 emissions costs due to the Study's assertion that most of the available emission data is considered old and the impacts are very small.[30]

3.11 Economic Development Benefits

The Docket 4600 Framework includes consideration of societal economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modelling. Therefore, economic development impacts (e.g., economic growth, job creation) can be quantified using the Regional Economic Models, Inc. (REMI) model of the Rhode Island economy, which estimates the increased economic activity resulting from investments. The overall societal impact is measured by net Rhode Island gross domestic product (GDP), which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms.

Rhode Island Energy agrees with Docket 4600 that economic development benefits are important. However, including these benefits in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits, which can discredit other more precise components of the BCA. Additionally, because the benefits can be large, they create a "masking" effect. For these reasons, the RI NPA BCA Model did not consider economic development benefits in its BCA.

3.12 Contract/Solution Costs

The contract or solution cost is the direct cost for the NPA. This could be a payment schedule to a third party or for paid customer participation (e.g., targeted energy efficiency or demand response). These cost schedules are typically based on an annual, semi-annual, or monthly cadence. Additionally, these cost schedules may involve an annual escalator. In cases with a known, irregular cost schedule these costs can be entered manually in their respective years.

3.13 Administrative Costs

Administrative costs are related to the ongoing support of the NPA. Administrative costs can include evaluation, measurement, and verification (EM&V) costs, ongoing communications and information technology fees, or additional costs related to the post-implementation costs to keep the NPA viable. For each solution an annual expected administrative cost will be applied. In cases with a known, irregular admin cost schedule these costs can be entered manually in their respective years.

3.14 Utility Interconnection Costs

The interconnection cost is the cost for physically and digitally linking the solution to the gas system. Interconnection costs will be determined on a case-by-case basis regarding the specific system need and its respective targeted NPA. This cost will generally be a capital expenditure, initially borne by the utility, prior to the commercially viable date of the NPA solution.

[30] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf Page 56.

4. Benefit-Cost Calculations

The RI NPA BCA Model is a comparison tool to be utilized to analyze multiple solutions with respective technologies to assess their cost-effectiveness. Currently two technology types are assessed: Energy Efficiency and Demand Response. The RI NPA BCA Model will be expanded as new technologies or solutions evolve. The RI NPA BCA Model is structured to allow for any given solution to utilize any, all, or a combination of these technologies on a per solution basis.

As prescribed by the Standards, the RI NPA BCA Model uses a "discount rate that appropriately reflects the risks of the investment". The Company maintains that the most reasonable rate at which to discount future year costs and benefits is the Company's after-tax Weighted Average Cost of Capital (WACC) (currently 6.97%)[31] since the NPA investments are utility investments, and after-tax WACC is the Company's effective discount rate.

The total benefits will equal the sum of the net present value (NPV) of each annual benefit component:

- [Electric Benefits + DRIPE Benefits + Natural Gas Energy Benefits + Natural Gas Supply Capacity Benefits + Natural Gas Distribution Capacity Benefits + Natural Gas Supply Infrastructure + Natural Gas Supply Infrastructure Site-Specific Benefits + Delivered Fuel Oil Benefits + Water & Sewer Benefits + Value of Improved Reliability + Non-Energy Impacts + Non-Embedded GHG Reduction Benefits + Non-Embedded NOx Reduction Benefits + Non-Embedded SO_2 Reduction Benefits + Economic Development Benefits]

The total costs will equal the sum of the NPV of each annual cost component:

- [Contract/Participant Costs + Program Administrative Costs + Utility Interconnection Costs]

The RI Test benefit-cost ratio (BCR) will then equal:

- Total NPV Benefits ÷ Total NPV Costs

The BCA can then financially compare multiple solutions, regardless of technology type.

The NPA investment will be considered cost-effective if the BCR for the resource is greater than 1.0.

[31] "Docket No. 4770." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 29 Nov. 2017, www.ripuc.ri.gov/eventsactions/docket/4770page.html.

5. Appendices

Appendix 1	AESC 2021 Materials Source Reference
Appendix 2	Table of Terms

Appendix 1: AESC 2021 Materials Source Reference

Please refer to the following citation for the Appendix B, C and D data tables of the AESC 2021 Study materials.

> "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials.

Appendix 2: Table of Terms

Term	Definition
AESC	Avoided Energy Supply Components
AESC 2021 Study	Avoided Energy Supply Components in New England: 2021 Report
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
Capex	Capital expenditure
CO_2	Carbon dioxide
DER	Distributed Energy Resource
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effect(s)
EE	Energy Efficiency
EE Plan	Energy Efficiency Program Plan
EEP	Energy Efficiency Program
EERMC	Energy Efficiency and Resource Management Council
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
ESS	Energy Storage System
FERC	Federal Energy Regulatory Commission
GAME	Gas Asset Management and Engineering
GDP	Gross Domestic Product
GHG	Greenhouse gas
ISO	Independent Systems Operator
LAUF	Lost and Unaccounted for Gas
LCP	Least-Cost Procurement
LCP Standards	Least-Cost Procurement Standards
LDC	Local Distribution Company
LMU	Locational Marginal Unit
MMBtu	Million British Thermal Unit
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Energy Reliability Corporation
NOx	Nitrogen oxides (NO, NO_2)
NPV	Net Present Value
NPA	Non-Pipeline Alternative

Term	Definition
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
Opex	Operational expenditure
PM	Particulate Matter
PTF	Pool Transmission Facilities
PTL	Pool Transmission Losses
PUC	Public Utilities Commission
RD&D	Research, Design, and Development
REC	Renewable Energy Credit
REMI	Regional Economic Models, Inc.
RGGI	Regional Greenhouse Gas Initiative
RI	Rhode Island
RI NPA BCA Model	Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Model
RI NWA BCA Model	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model
RI NWA BCA TRM	Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Technical Reference Manual
RI NWA BCA TRM	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Technical Reference Manual
RI Test	Rhode Island Benefit-Cost Test
ROP	Rest of Pool
RPS	Renewable Portfolio Standards
SO_2	Sulfur dioxide
T&D	Transmission and Distribution
TRC Test	Total Resource Cost Test
TRM	Technical Reference Manual
US	United States of America
WACC	Weighted Average Cost of Capital

Appendix 10. Expected Valuation

Introduction

Expected valuation is a common practice for accounting for probabilities of different outcomes. In essence, the expected value of an action is the sum of its probability-weighted values. Expected value may be applied when there are multiple possible outcomes that may result from an action. By applying expected value, we can appropriately internalize the range of likely outcomes; not applying expected value may result in over-emphasizing (under-emphasizing) a particular outcome because of the implicit assumption that outcome will result with 100% (0%) certainty.

In this appendix, Rhode Island Energy describes its proposed application of expected value. Rhode Island Energy will begin by considering expected valuation as a sensitivity analysis to certain benefit-cost assessments. Through gaining experience with applying expected value, Rhode Island Energy can contemplate refining its methodology for deciding when and how to apply expected value.

When to apply expected value

Generally, in the short-term, Rhode Island Energy will apply expected value as a sensitivity analysis in situations where Rhode Island Energy conducts a benefit-cost assessment for investment choices between two alternatives, and for which it is feasible to identify potential outcomes and estimate the probabilities of those outcomes occurring. Rhode Island Energy recognizes that there may be unforeseen complexities that prevent full application of expected value and considers the next few years to be an exploratory, learning experience.

As a first step in this learning experience, Rhode Island Energy will first apply expected value to investment decisions regarding non-wires (non-pipes) solutions relative to wires (pipes) solutions, where the outcomes are differences in the deferral term of the wires (pipes) solution.[33]

In the longer-term, Rhode Island Energy can potentially apply expected value to more complex decisions, including but not limited to decisions between more than two alternatives and decisions with more than two potential outcomes.

Whenever Rhode Island Energy applies expected value, Rhode Island Energy will document the exact method for each step contained in the methodology, all assumptions, and all justifications or underlying evidence required for a reader to understand and replicate the calculations.[34]

[33] For simplicity, Rhode Island Energy will just refer to wires and non-wires solutions for the remainder of this document. Rhode Island Energy does intend to apply expected value, as described herein, to pipes and non-pipes solutions, as appropriate and feasible.
[34] Subject to protection of confidential data and sources.

Methodology for applying expected value

In this section, Rhode Island Energy summarizes its proposed methodology for applying expected value based on three discreet steps: (1) identifying the relevant scenarios, (2) assigning value to each scenario, (3) estimate probability for each scenario, (4) conduct the relevant comparison in the benefit-cost assessment. This methodology was heavily informed by Ross, Trietch, and Gill (2022), included in the appendix for easy reference. The appendix also contains a summary of stakeholder engagement regarding expected value and an Excel tool to aid in illustrative and conceptual understanding of expected value.

Terminology

First, Rhode Island Energy provides the following working definitions with the objective of aiding readers' clarity throughout this document.

Decision

A decision is a choice between at least two alternatives (i.e., throughout this document, we assume a planner is deciding between a wires solution and a non-wires solution to achieve the objective of resolving a specific grid need).

Alternative

An alternative is one option being seriously considered in a decision (i.e., throughout this document, we assume there exists two, and only two, alternatives: a wires solution and a non-wires solution).

Outcome k

An outcome is some future state of the world that may (or may not) result from the decision. In Ross, Trietch, and Gill (2021), 'scenario' is used synonymously with 'outcome'.

Probability $P_{outcome\ k}$

Probability is the likelihood of an outcome occurring. A 100% probability indicates that an outcome is certain to occur; no other outcome is possible. A 0% probability indicates that an outcome is certain to never occur. A probability between 0% and 100% indicates that at least two (or more) outcomes are possible. The probabilities of all possible outcomes must sum to 100%.

Cost

In this document, Rhode Island Energy uses 'cost' to refer to the amount Rhode Island Energy would need to pay for an alternative. This cost is what would be proposed to be recovered from customers, not including appropriate return.

Deferral Term $T_{deferral}^{outcome\ k}$

The deferral term is the duration of time that one alternative can be postponed, delayed, or deferred if another alternative is instead implemented. Note that some prior documentation used 'deferral period' synonymously with 'deferral term'.

Deferral Value $T_{deferral}^{outcome\ k}$

Deferral value is the net benefit, according to the appropriate benefit-cost assessment, associated with an alternative being postponed, delayed, or deferred for a specific deferral term. Note that the deferral value must reference the deferral term; deferral value is different for each deferral term, all else equal.

Wires Lifetime T_{wires}

The time period over which the wires solution would be in place. Wires lifetime may correspond with the depreciation period.

Rate of Return r

The rate of return is the incremental revenue required for a wires solution.

Discount Rate i

The discount rate is the assumed time value of money used in calculating net present value. The discount rate may correspond to inflation rate.

Given Input

Applying expected value requires several sets of input. The Steps below describe what input is required to perform the step and what outputs are produced. Where not otherwise discussed, the wires cost $Cost_{wires}$, wires lifetime T_{wires}, rate of return r, and discount rate i are all taken as given, supported by prior engineering and financial analysis not described herein. In any public-facing documentation, Rhode Island Energy will state its assumptions, underlying analysis, and any other caveats for the values of these inputs. While these inputs are given, Rhode Island Energy may conduct a sensitivity analysis to understand how big of a driver these factors are in the decision.

Step 1: Identify the Relevant Outcomes

Inputs

- Wires lifetime T_{wires}

Outputs

- Deferral term for each outcome $T_{deferral}^{outcome\ k}$

Description

Rhode Island Energy will assess at least the following two outcomes:

(1) Implementing the non-wires alternative delays the need to implement the wires alternative by the deferral term.
(2) Implementing the non-wires alternative avoids the need to implement the wires alternative. In this outcome, the deferral term is equivalent to the lifetime of the wires solution.

At the end of the deferral term (outcome 1) or the lifetime of the wires solution (outcome 2), a new decision will be made that accounts for the specific grid need and relevant alternatives at that time (this new decision does not factor into the decision at hand).

Rhode Island Energy may choose to assess additional outcome(s) if that outcome(s) has a sufficiently likely probability of occurring. If Rhode Island Energy does choose to assess additional outcome(s), Rhode Island Energy will describe the outcome(s) and provide its reasoning for including that outcome(s) in its application of expected value.

Rhode Island Energy may also supplement its application of expected value by estimating the hypothetical deferral term for which deferral value is equal the cost of the non-wires solution. In other words, Rhode Island Energy will assume the deferral value is equal to the cost of the wires solution. In this case, Rhode Island Energy interprets the hypothetical deferral term as the deferral term required to come to fruition for the non-wires alternative to 'break even' with the wires alternative. In other words, in an outcome where this deferral term is realized, Rhode Island Energy would be indifferent to either wires or non-wires alternative, assuming all else equal.

Step 2: Assign Value to Each Outcome
Inputs

- Discount rate: i
- Rate of return: r
- Annual revenue requirement at year t: RR_t
- Deferral term for each outcome $T_{deferral}^{outcome\ k}$

Outputs

- Net present values: NPV_{wires}, $NPV_{outcome\ k}$
- Deferral value of outcome k: ${V_{deferral}}^{k}$

Description

Rhode Island Energy takes as a given the annual revenue requirement for the wires solution, as determined by annual depreciation and annual return (given rate of return r) for years $t = 1$ through $t = T_{wires}$. Rhode Island Energy calculates net present value of the wires solution using these annual values and the discount rate:

$$NPV_{wires} = \sum_{t=1}^{t=T_{wires}} \frac{RR_t}{(1+i)^t}$$

Rhode Island Energy will adjust the annual revenue requirement for the wires solution for each of the deferral periods identified out potential outcomes in Step 1: $T_{deferral}^{outcome\ k}$. In the simplest case, this adjustment entails delaying the implementation of the wires solution until $T_{deferral}^{outcome\ k}$. Net present value is calculated in the same manner:

$$NPV_{outcome\ k} = \sum_{t=T_{deferral}^{outcome\ k}}^{t=T_{deferral}^{outcome\ k}+T_{wires}} \frac{RR_t}{(1+i)^t}$$

The deferral value associated with a particular outcome is the difference in net present value relative to the net present value of the wires solution:

$$V_{deferral}{}^{k} = NPV_{wires} - NPV_{outcome\ k}$$

$V_{deferral}{}^{k}$ should nearly always be a positive value. This stems from the time value of money. There may be cases in which $V_{deferral}{}^{k}$ is negative, but those cases would require significant adjustments to annual revenue requirement beyond simply delaying implementation of the wires solution; such adjustments are not contemplated within this document.

Rhode Island Energy may choose to run and present sensitivity analyses using one or more different discount rates.

Step 3: Estimating Probability of Each Outcome
Inputs

- Underlying data and analysis

Outputs

- Probability of each outcome $P_{outcome\ k}$

Description

This Step is likely the Step that will have the most evolution as Rhode Island Energy gains experience in applying expected value. For this reason, Rhode Island Energy attempts to build flexibility into this document.

Rhode Island Energy’s objectives in estimating probability are (1) using data-driven and replicable methods, (2) using defensible and understandable methods, and (3) doing our due diligence in ground-truthing and retrospective review. In other words, Rhode Island Energy recognizes it has room to learn and doesn’t want to preemptively restrict its learning by prescribing a specific method. Rhode Island Energy will present its probabilities for each outcome, describe its underlying methodology for estimating those probabilities, and include relevant data sources. Rhode Island Energy invites feedback, questions, concerns, and recommendations from external stakeholders regarding its methodology for estimating probabilities of outcomes on an ongoing basis specific to each decision.

Rhode Island Energy may also include an estimation of the probabilities of outcomes required for the net present value of the wires solution to equal the net present value of the non-wires solution. Similar to the break-even analysis in Step 1, understanding the breakeven probabilities (e.g. an 80% probability that Outcome 1 occurs and a 20% probability that Outcome 2 occurs) will help Rhode Island Energy (and external stakeholders) ask the question of whether those probabilities are plausible, which will aid in ground-truthing (i.e. gut checking) the estimated probabilities.

For more information about methods of estimating probabilities, Rhode Island Energy refers readers to Ross, Trietch, and Gill (2022), though notes those methods are not a comprehensive listing of options.

Step 4: Conduct the Cost Comparison
Inputs

- Deferral value of outcome k: ${V_{deferral}}^{k}$
- Probability of each outcome: $P_{outcome\ k}$

Outputs

- Expected deferral value: $EV_{deferral}$

Description

Rhode Island Energy will calculate expected deferral value by summing the probability-weighted deferral values for each outcome:

$$EV_{deferral} = \sum_{outcome=1}^{outcome=K} \left(P_{outcome\ k} * {V_{deferral}}^{k}\right)$$

The cost comparison of interest is the cost of the non-wires solution to the expected deferral value. If the cost of the non-wires solution is equal to the expected deferral value, then Rhode Island Energy should be theoretically indifferent to the two alternatives, all else equal. If the cost of the non-wires solution is less than the expected deferral value, then the non-wires solution is the financially preferred alternative, all else equal. If the cost of the non-wires solution is more than the expected deferral value, then the wires solution is the financially preferred alternative, all else equal.

<u>Future Work</u>
Rhode Island Energy expects to refine its application of expected value as it gains experience. Rhode Island Energy welcomes further discussion and research with external stakeholders, with the following topics being of particular interest:

- Working through a similar application methodology for decisions about non-pipes solutions.
- Identifying and integrating an outcome where the non-wires solution is less than 100% effective. In other words, including some measure of risk for alternatives.
- Expanding the set of alternatives and conducting the cost comparison across all alternatives comprehensively.
- Quantifying and internalizing option value: the value gained by waiting to make a decision.

Stakeholder Engagement

In meetings of the System Reliability Procurement Technical Working Group in prior years, the concept of expected value has arisen. These discussions led to three representatives of members of the System Reliability Procurement Technical Working Group to publish a whitepaper on the concept, accepted and presented by the American Council for an Energy Efficiency Economy (ACEEE) in 2022. This concept was also presented to the Association of Energy Savings Professionals (AESP) in 2023. The whitepaper is included as an appendix for reference.

The System Reliability Procurement Technical Working Group further discussed application of expected value in its meetings in 2023:

- January 2023: Review of the concept of expected value, including key points from Ross, Trietch, and Gill (2022)
- February 2023: Discussion of identifying outcomes, applying probabilities, and estimating expected value
- April 2023: Application of expected value to a conceptual example adapted from a real-life non-wires solution request for proposals
- May 2023: Delivery of drafted Q1 deliverables (draft version of this appendix; a conceptual Excel Tool; and Ross, Trietch, and Gill (2022))