National Grid

The Narragansett Electric Company

2021-2023 System Reliability Procurement Three-Year Plan

November 20, 2020

Submitted to:
Rhode Island Public Utilities Commission

RIPUC Docket No. 5080

Submitted by:
nationalgrid

Filing Letter &
Motion

Andrew S. Marcaccio
Senior Counsel

November 20, 2020

VIA ELECTRONIC MAIL

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

RE: Docket 5080 – System Reliability Procurement 2021-2023 Three-Year Plan

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please find the Company's System Reliability Procurement ("SRP") 2021-2023 Three-Year Plan (the "SRP Three-Year Plan" or "Plan"). The SRP Three-Year Plan is being filed in accordance with R.I. Gen. Laws § 39-1-27.7 and Section 4.6 of the Least Cost Procurement ("LCP") Standards.[2]

This SRP Three-Year Plan, as filed, is a settlement among the Company, Acadia Center, the Energy Efficiency and Resource Management Council ("EERMC")[3], the Green Energy Consumers Alliance (formerly People's Power & Light), the Rhode Island Office of Energy Resources ("OER"), the Rhode Island Division of Public Utilities and Carriers ("Division"), and the Northeast Clean Energy Council ("NECEC") (collectively, the "Parties").

In support of the Plan, the Company has included joint pre-filed direct testimony of Matthew Chase, Andrew McClintock, and Timothy Roughan. Please note that the joint pre-filed direct testimony is being submitted on behalf of the Company and not on behalf of the other Settlement Parties as they have not had an opportunity to review the testimony prior to this filing.

As explained in the Plan, the Company respectfully requests that the Rhode Island Public Utilities Commission ("PUC") approve the programmatic proposals presented in the SRP Three-Year Plan. For a list of the requested approvals, please see Table 1 within the Plan and the

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[1] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by five hard copies filed with the Clerk within 24 hours of the electronic filing.

[2] The LCP Standards were approved by the PUC on July 23, 2020 in Docket No. 5015.

[3] On November 12, 2020, the EERMC voted to approve the SRP Three-Year Plan.

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Company's pre-filed joint direct testimony. Please note that the proposals made by the Company in this SRP Three-Year Plan are all programmatic in nature and do not require any additional, incremental funding.

Please be advised that the Company considers Appendix 3-RI NWA BCA Model ("Appendix 3") of the Plan to be confidential. Pursuant to 810-RICR-00-00-1.3(H)(3) and R.I. Gen. Laws § 38-2-2(4)(B), the Company respectfully requests that the Commission treat Appendix 3 as confidential. In support of this request, the Company has enclosed a Motion for Confidential Treatment. In accordance with 810-RICR-00-00-1.3(H)(2), the Company also respectfully requests that the Commission make a preliminary finding that Appendix 3 is exempt from the mandatory public disclosure requirements of the Rhode Island Access to Public Records Act.

As previously mentioned, the proposals made by the Company in this SRP Three-Year Plan do not require any approvals for funding at this time. Rather, this SRP Three-Year Plan establishes the framework for future SRP investment proposals, which may be filed in accordance with Chapter 5 of the LCP Standards, and SRP Year-End Report filings that will be submitted during calendar years 2021 to 2023.

Highlights of the proposed framework include an SRP funding mechanism (See Section 5 of the Plan); an SRP performance incentive mechanism (See Section 6 of the Plan); the details of the Company's Non-Wires Alternative ("NWA") Program in Rhode Island (See Section 7 of the Plan); and the development of an Non-Pipeline Alternative ("NPA") Program in Rhode Island (See Section 8 of the Plan).

Thank you for your attention to this filing. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5080 Service List
Jon Hagopian, Esq.
John Bell, Division

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY	:	
d/b/a NATIONAL GRID'S THREE-YEAR SYSTEM	:	DOCKET NO. 5080
RELIABILITY PROCUREMNT (SRP) PLAN 2021-2023	:	

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company") hereby respectfully requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein. The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The record that is the subject of this Motion that requires protective treatment from public disclosure is an Excel File labeled as Appendix 3 - RI NWA BCA Model ("Appendix 3"). Appendix 3 is an appendix to the Company's Three-Year System Reliability Procurement ("SRP") Plan 2021-2023 which was filed by the Company on November 20, 2020 in the above-referenced docket. National Grid requests protective treatment of Appendix 3 in accordance with 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(B).

I. LEGAL STANDARD

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA. See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

II. BASIS FOR CONFIDENTIALITY

Appendix 3, which is the subject of this Motion, is exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(B) as "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." *The Attorney General's Guide to Open Government in Rhode Island 6th Edition*[1] provides guidance as to the scope of R.I. Gen. Laws § 38-2-2(4)(B)'s applicability. It states that:

> If a request is made for financial or commercial information that a person is obliged to provide to the government, it is exempt from disclosure if the disclosure is likely either: (1) to impair the government's ability to obtain information in the future, or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. If a request is made for financial or commercial information that is provided to the government on a voluntary basis, it is exempt from disclosure if the information "is a kind that would customarily not be released to the public by the person from whom it was obtained." The Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001).

Appendix 3 is the Rhode Island non-wires alternative ("NWA") benefit-cost analysis model that the Company developed to more accurately assess the benefits and costs of NWA opportunities. This model is proprietary to the Company and the Company considers this model to be commercial information. National Grid would customarily not release this model to the public and its submission of Appendix 3 stems from a regulatory directive issued by the PUC via Section 1.3.B of the Least Cost Procurement Standards. Accordingly, National Grid is providing

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[1] http://www.riag.ri.gov/Forms/AGguidetoopengovernment.pdf

Appendix 3 to the PUC to fulfil its regulatory responsibilities. Therefore, Appendix 3 is exempt from public disclosure "if the disclosure is likely either: (1) to impair the government's ability to obtain information in the future, or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained." See *The Attorney General's Guide to Open Government in Rhode Island 6th Edition*, p. 22.

The release of Appendix 3 is likely to cause substantial harm to the competitive position of National Grid. Appendix 3 includes sensitive information and other commercial details regarding the Company's analysis of NWA opportunities. Disclosing this information to the public could harm the Company's ability to procure third-party NWA solution bids in the most cost-effective and unbiased manner and, ultimately, harm customers.

III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of Appendix 3.

Respectfully submitted,

NATIONAL GRID
By its attorney,

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Andrew S. Marcaccio (#8168)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-4263

Dated: November 20, 2020

CERTIFICATE OF SERVICE

I hereby certify that on November 20, 2020, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 5080.

Joanne M. Scanlon

PRE-FILED JOINT DIRECT TESTIMONY

OF

MATTHEW CHASE, ANDREW MCCLINTOCK,

AND TIMOTHY ROUGHAN

November 20, 2020

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I. INTRODUCTION

Matthew Chase

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

A. My name is Matthew Chase. My business address is 477 Dexter Street, Providence, Rhode Island 02907.

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

A. I am employed by National Grid USA Service Company, Inc. (National Grid USA) as a project manager in the Customer Reliability Analytics and Non-Wires Alternative (NWA) Solutions group of Electric Asset Management. In this role, I am responsible for the System Reliability Procurement (SRP) regulatory filing of The Narragansett Electric Company d/b/a National Grid (the Company or National Grid) and NWA projects in Rhode Island.

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

A. In 2014, I graduated from Worcester Polytechnic Institute with a Bachelor of Science Degree in Electrical and Computer Engineering. In 2015, I worked at Zachry Nuclear Engineering as an Electrical Engineer. From January 2015 to April 2016, I performed various work involving design, construction, and implementation of electrical and nuclear systems. In May 2016, I joined National Grid USA as an Associate Engineer in the Advanced Grid Engineering division of the Network Solutions group. In June 2017, I was promoted to Engineer in the Non-Wires

Alternative Offerings group in New Energy Solutions at National Grid USA. From June 2017 to December 2017, I was a project engineer for NWA projects in Rhode Island and Massachusetts. In January 2018, I began my current position.

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

A. Yes, I testified before the PUC in Docket No. 4889 regarding the 2019 SRP Report and in Docket No. 4980 regarding the 2020 SRP Report.

Andrew McClintock

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

A. My name is Andrew McClintock. My business address is 40 Sylvan Road, Waltham, MA 02451.

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

A. I am employed by National Grid USA Service Company, Inc. (National Grid USA) as a financial analyst in the Customer Reliability Analytics and NWA Solutions group of Electric Asset Management.

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

A. In 2014, I graduated from American University with a Bachelor of Arts in Economics followed by dual degrees, Masters' of Science in Finance and in Business Administration, from Northeastern University in 2019. I started at National Grid in 2017 within the New England Resource Planning group before being transferred to my current role in the NWA team in February 2020. Prior to National Grid, I worked as a pricing analyst for a telecommunications firm.

Q. Have you previously testified before the PUC?

A. No.

<u>Timothy Roughan</u>

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

A. My name is Timothy Roughan. My business address is 40 Sylvan Road, Waltham, MA 02451.

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

A. I am employed by National Grid USA as the Director of Regulatory Strategy for Rhode Island.

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

A. I have a Bachelor of Science in Mechanical Engineering from Worcester Polytechnic Institute. Since 1982, I have worked at National Grid USA and its predecessor companies in a variety of roles. Recently, I have worked extensively on matters relating to distributed generation and NWA.

Q. Have you previously testified before the PUC?

A. Yes, I have testified before the PUC in numerous dockets, including several SRP dockets beginning in 2009. I most recently testified before the PUC in Docket Nos. 4770 and 4780.

II. <u>PURPOSE OF JOINT TESTIMONY</u>

Q. What is the purpose of this joint testimony?

A. The purpose of this joint testimony is to present the 2021-2023 SRP Three-Year Plan (the Plan), which the Company developed as part of an iterative process with the following parties: Acadia Center, the Energy Efficiency and Resource Management Council (EERMC), the Green Energy Consumers Alliance (formerly People's Power & Light), the Rhode Island Office of Energy Resources (OER), the Rhode Island Division of Public Utilities and Carriers (Division), and the Northeast Clean Energy Council (NECEC) (collectively, the Parties). Implementation of the Plan will allow the Company to meet its obligation to provide safe, reliable, and efficient electric service for customers at a reasonable cost. The proposed Plan is attached as Schedule 1 to this testimony.[1]

III. 2021-2023 SYSTEM RELIABILITY PROCUREMENT THREE-YEAR PLAN OVERVIEW

Q. What is the purpose of System Reliability Procurement?

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

Q. What is the role of the Company with respect to SRP?

A. The role of National Grid with respect to SRP is to: (1) identify potential NWA and Non-Pipeline Alternative (NPA) opportunities; (2) source viable solutions that address system needs and reduce, avoid, or defer distribution wires and pipes investments; and (3) support projects and programs that enable such activity.

[1] The 2021-2023 SRP Three-Year Plan presented in this filing is the first standalone SRP three-year plan submitted to the PUC pursuant to R.I. Gen. Laws § 39-1-27.7.

Q. How did the Company prepare this filing for review by the PUC?

A. The Company prepared a first draft of the Plan and submitted it to the Parties on July 24, 2020 for review. In preparing the Plan, the Company had meetings and discussions with members of the System Reliability Procurement Technical Working Group (SRP TWG).[2] Meetings and discussion with SRP TWG members continued through three draft versions of the Plan up until November 12, 2020, when the EERMC voted on and approved the Plan. The Company subsequently filed the Plan with the PUC on November 20, 2020.

Q. Are there any important changes made to the SRP Program in this filing that the Company wishes to highlight?

A. Yes. In the Plan, the Company proposes the development of an NPA program in Rhode Island within the overall SRP Program. This NPA program would be new and would provide the path for alternative solutions on the gas system, similar in nature to how the NWA program operates within SRP and with respect to the electric system. The proposal for NPAs in system planning and the corresponding development plan are detailed in Section 8 of the Plan.

Additionally, the Company proposes the SRP Year-End Report filing mechanism to provide status and implementation updates through an annual report. This SRP Year-End

[2] Members of the SRP TWG presently include the Company, Acadia Center, the Division, Green Energy Consumers Alliance (formerly People's Power & Light), OER, NECEC, several EERMC members, and representatives from the EERMC's Consultant Team (EERMC C-Team).

Report filing mechanism is in line with Least-Cost Procurement Standards (LCP Standards) requirement Section 4.4.B and is detailed in Section 12 of the Plan.

Q. What approvals is the Company requesting from the PUC in this filing?

A. The Company requests the following approvals from the PUC listed in the table below:

Table 1. Summary of Requested Rulings for SRP in 2021-2023

SRP Section	SRP Initiative/Proposal	Requested Ruling
5	SRP Funding Mechanism	The Company requests the PUC approve the Company's proposal that operational expenditure (opex)-type SRP investments be funded through the System Benefit Charge, or Energy Efficiency (EE) Charge, on customers' bills as described in Section 5 of the Plan.
5	SRP Funding Mechanism	The Company requests the PUC approve the Company's proposal that capital expenditure (capex)-type SRP investments be filed and proposed in an SRP Investment Proposal as described in Section 5 of the Plan.
6	SRP Performance Incentive Mechanism	The Company requests the PUC approve the Company's proposed performance incentive mechanism (PIM) for calendar years 2021 through 2023 as described in Section 6 of the Plan.
7.2	NWA Screening Criteria	The Company requests the PUC approve the proposed NWA screening criteria for Rhode Island as detailed in Table 5 of the Plan for calendar years 2021 through 2023.
8	NPAs in System Planning	The Company requests the PUC approve the development plan for the Non-Pipeline Alternatives program in calendar years 2021 through 2023 as described in Section 8 of the Plan.

SRP Section	SRP Initiative/Proposal	Requested Ruling
12	SRP Timeline: SRP Investment Proposals	The Company requests the PUC rule on SRP Investment Proposals within 60 days of filing as described in Section 12 of the Plan.
12	SRP Timeline: Year-End Reports	The Company requests the PUC approve the annual reporting plan for SRP Year-End Reports for calendar years 2021 through 2023 as described in Section 12 of the Plan.

Q. How does SRP meet Least-Cost Procurement (LCP) law?

A. SRP meets LCP law through: (1) identification of distribution projects that meet certain screening criteria for potential NWAs or NPAs that reduce, avoid, or defer distribution wires or pipes investments, respectively; (2) the development and implementation of NWA or NPA projects; and (3) procurement of NWA or NPA solutions from third-party solution providers. NWA and NPA projects must be inherently cost-effective, reliable for the electric distribution system, prudent, and environmentally responsible. Solutions for NWAs are typically comprised of distributed generation (DG) resources.

Q. How does the Company assess the LCP Standards?

A. The Company assesses the LCP Standards at the project/program level.

Q. Why is there no detailed assessment of the LCP Standards criteria (cost-effective, reliable, prudent, environmentally responsible, and less than the cost of best alternative utility reliability procurement) in the 2021-2023 SRP Three-Year Plan?

A. There is no detailed assessment of the LCP Standards criteria in the Plan because there are no investment proposals. LCP Standards criteria assessment will be done per project/program proposal in each respective SRP Investment Proposal filing. For example, the LCP Standards criteria assessment for the potential Bristol 51 NWA investment will be detailed in the SRP Investment Proposal filing for the Bristol 51 NWA project.

Q. Where is information on LCP Standard criterion "cost-effective"?

A. The Company has programmatically addressed LCP Standard criterion "cost-effective" in Section 3.2 of the Plan.

Q. Where is information on LCP Standard criterion "reliable"?

A. The Company has programmatically addressed LCP Standard criterion "reliable" in Section 3.3 of the Plan.

Q. Where is information on LCP Standard criterion "prudent"?

A. The Company has programmatically addressed LCP Standard criterion "prudent" in Section 3.4 of the Plan.

Q. Where is information on LCP Standard criterion "environmentally responsible"?

A. The Company has programmatically addressed LCP Standard criterion "environmentally responsible" in Section 3.5 of the Plan.

Q. Where is information on LCP Standard criterion "lower than the cost of the best alternative Utility Reliability Procurement"?

A. The Company has programmatically addressed LCP Standard criterion "lower than the cost of the best alternative Utility Reliability Procurement" in Section 3.6 of the Plan.

Q. How does the Plan align with the Docket 4600 Framework?

A. In Sections 3.1 and 3.2 and Appendices 3 and 4 of the Plan, the Company details how the Rhode Island NWA Benefit-Cost Analysis Model (RI NWA BCA Model) is the cost test for the SRP program and how the RI NWA BCA Model aligns with the cost-effectiveness criterion of the LCP Standards and Docket 4600 Framework. SRP investments, such as NWA or NPA projects, will be filed in the SRP Investment Proposal filing mechanism and will each assess their individual alignment with the Docket 4600 Framework.

The Plan advances Docket 4600 Framework because: (1) it addresses the challenge of climate change and other forms of pollution with the commitment to develop an NPA program in Rhode Island; (2) it appropriately compensates the distribution utility for the services it provides through the Savings-Based Incentive mechanism proposal; and (3) it aligns distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive because of the Company's commitment to several stakeholder and policy objectives. The Plan is neutral on the other Docket 4600 Framework goals because there are no NWA or NPA proposals embedded in the SRP Three-Year Plan filing.

Q. How does the 2021-2023 SRP Three-Year Plan coordinate with Power Sector Transformation (PST) and other required Company programs and filings in Rhode Island?

A. In Section 11 of the Plan, the Company has detailed how the Plan coordinates with other Company programs and filings. The Company recognizes that improved synchronization between SRP and PST, the Energy Efficiency Program Plan (EE Plan), the Infrastructure, Safety and Reliability (ISR) Plans, the Renewable Energy Growth (REG) Program, the Grid Modernization Plan (GMP), and the Advanced Metering Functionality (AMF) Business Case is necessary and intends to maintain and improve coordination between these filings.

Q. Please explain how funds are balanced for the SRP Program.

A. The SRP Program itemizes the recommended work activities for each calendar year by project/program and provides budgets for operation and maintenance expenses for the respective SRP projects and programs. After the end of each calendar year, the Company balances SRP funds by comparing the SRP Program's projected expense levels used for establishing the revenue requirement to actual or allowed investment and expenditures on a cumulative basis and reconciles the revenue requirement associated with the actual investment and expenditures to the revenue billed from the rate adjustments implemented at the beginning of each calendar year.

Q. Please summarize the categories of SRP spending covered by the Plan.

A. The proposed Plan addresses the following budget and work categories for the three-year cycle starting January 1, 2021 and ending December 31, 2023 (CY 2021 through 2023): (1) the SRP Performance Incentive Mechanism (PIM); (2) proposed NWA projects; (3) proposed NPA projects; (4) new enhancements to the Rhode Island System Data Portal (Portal); and (5) SRP Market Engagement.

Q. Please review the CY 2021 through 2023 SRP Funding Request.

A. In this filing, no new enhancements or new work are currently planned for the Rhode Island System Data Portal (Portal) and the SRP Market Engagement program. Therefore, there are no additional or incremental costs for these programs expected for calendar years 2021 through 2023. Instead, the Company requests approval on programmatic proposals, as stated in this testimony in Table 1. The proposed funding and the cost recovery mechanisms (CRM) are summarized in the table below for each of these key work categories for CY 2021 through 2023.

Please note that the cells that state "TBD" in the table below indicate unknowns because SRP plans and project development during future years will determine applicable funding requests for those items. Also note that the CRM for NWAs and NPAs is to be determined in the proposal stage, based on the specific solution's ownership model. Funding requests and CRM will be proposed and detailed in the respective SRP Investment Proposal filing for each NWA and NPA project.

Table 2. Summary of Anticipated 2021-2023 SRP Funding Requests

SRP Section	SRP Initiative/Proposal	CRM	CY 2021	CY 2022	CY 2023
6	SRP PIM	EE Charge	TBD	TBD	TBD
7	NWAs in System Planning	TBD	TBD	TBD	TBD
8	NPAs in System Planning	TBD	TBD	TBD	TBD
9	Rhode Island System Data Portal	EE Charge	$0	$0	$0
10	SRP Market Engagement	EE Charge	$0	$0	$0
		Total	**$0**	**$0**	**$0**

IV. SRP PERFORMANCE INCENTIVE MECHANISM PROPOSAL

Q. What is the proposed SRP Performance Incentive Mechanism (PIM)?

A. The SRP PIM is a savings-based mechanism that incentivizes the Company to implement distributed energy resources (DERs), targeted energy efficiency (EE), or targeted demand response (DR) that have a higher operational risk factor when implemented as NWA or NPA solutions in comparison to wires or pipeline solutions.

The calculation methodology for the SRP PIM is detailed in Section 6 of the Plan. The SRP PIM encompasses incentives for the Company to install DERs as a result of SRP initiatives. The Company is obligated to demonstrate that DERs were installed as a result of the SRP initiatives. This demonstration requires: (1) the project contract between the solution provider and the Company; (2) confirmation that the SRP solution was installed by the in-service need date of the SRP opportunity; and (3) measured output at the feeder during peak hours showing the specific investment's contribution to mitigating or eliminating the specified system need. For the Company to earn savings-based incentives on DERs, targeted EE, or targeted DR, they must be deemed cost-effective according to the Rhode Island cost-effectiveness framework established in the PUC's Docket 4600 Guidance Document.

Q. When does the Company propose the earnings for a specific project's savings-based incentive?

A. The Company will propose the incentive earnings for a specific and implemented project's savings-based incentive in an annual SRP Investment Proposal filing following year-end analysis of the SRP project's performance measurement. The SRP PIM proposal for a specific SRP project would detail the requested incentive value, the corresponding calculation, and would be based off the prior year's actual solution performance measurements. This allows for full calendar year assessment for savings-based incentives.

Q. What Savings-Based Incentives does the Company propose at this time?

A. The Company does not propose any savings-based incentive earnings at this time. Incentive earnings will be proposed in the respective SRP Investment Proposal filing.

V. NWAs IN SYSTEM PLANNING

Q. Please provide a summary of the NWA screening process.

A. The NWA screening process uses the following proposed criteria to assess potential opportunities to reduce, avoid or defer distribution wires solutions over an identified period:

Table 3. Screening Criteria for NWA Opportunities

Criteria Type	Criteria Requirement
Project Type Suitability	Project types include Load Relief and Reliability.[3] The need is not based on Asset Condition. Other types have minimal suitability and will be reviewed as suitability changes due to State or Federal policy or technological changes. If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.
Timeline Suitability	Start date of system need is at least 24 months in the future.
Cost Suitability	Cost of wires option is greater than $1M.

[3] For definition of reliability, see "Docket 3628: Proposed Service Quality Plan." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2004, www.ripuc.ri.gov/eventsactions/docket/3628page.html.

Additionally, in its discretion, the Company may pursue a project that does not pass one or more of these criteria if there is reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

This discretion is used in cases where an NWA may not defer the entire distribution project but could defer part of the overall scope of the project. This is referred to as a partial NWA. The detailed process for screening and developing potential NWA opportunities is provided in Section 7.3 of the Plan. The NWA evaluation process for received third-party solution bids is detailed in Section 7.4 of the Plan.

Q. What are the current NWA screenings and opportunity analyses taking place?

A. The Company is currently screening for NWA opportunities in the following distribution area studies: Northwest Rhode Island, Central Rhode Island West, and South County West.

Additionally, the Company is currently pursuing the following potentially viable NWA opportunities: Bonnet 42F1, Bristol 51, and South Kingstown. These in-progress opportunities are detailed in Section 7.5 and Appendix 2 of the Plan.

VI. PROPOSAL FOR NPAs IN SYSTEM PLANNING

Q. What are Non-Pipeline Alternatives?

A. Non-Pipeline Alternatives (NPAs) is the inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or "pipeline investment."

NPAs are essentially the gas system equivalent of NWAs. NPAs are a new, developing aspect of the SRP Program, with the NPA program being developed to enable SRP to additionally address natural gas system needs in alignment with LCP law.

Q. What is the Company's proposal with respect to NPAs in system planning?

A. The Company proposes to develop an NPA program in Rhode Island with screening criteria, planning process and integration with gas system planning, bid evaluation process, and an RI NPA BCA Model as constituent components. The NPA program development plan is detailed in Section 8.2 of the Plan.

VII. RHODE ISLAND SYSTEM DATA PORTAL

Q. What is the Company's proposed work on the Rhode Island System Data Portal in CY 2021 through 2023?

A. In this filing, no new enhancements or new work are currently planned for the Portal. This decision is based on current SRP TWG stakeholder and third-party solution provider feedback received to date. The Company will maintain engagement with SRP TWG stakeholders and third-party solution providers to ensure the Portal continues to meet the information access needs of the market.

Therefore, there are no additional or incremental costs for this program expected for calendar years 2021 through 2023.

VIII. SRP MARKET ENGAGEMENT

Q. What is the purpose of SRP Market Engagement?

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

Q. What does the Company propose for SRP Market Engagement in CY 2021 through 2023?

A. In this filing, no new enhancements or new work are currently planned for the SRP Market Engagement program. Therefore, there are no additional or incremental costs for this program expected for calendar years 2021 through 2023.

The Company has currently entered a maintenance phase with market engagement for the Rhode Island System Data Portal. Therefore, the only planned SRP Market Engagement activity for the Portal is to maintain web traffic analytics to the Portal landing page. These web traffic analytics have no cost to operate or acquire.

IX. CONCLUSION

Q. In your opinion does the 2021-2023 SRP Three-Year Plan fulfill the requirements established in relation to the safety and reliability of the Company's electric distribution system in Rhode Island?

A. Yes. The Plan is designed to establish the programmatic structure for NWA and SRP-related activities in Rhode Island that are necessary to meet the needs of Rhode Island customers and maintain the overall safety and reliability of the Company's electric distribution system. The Company believes that the proposed Plan accomplishes these objectives. As such, the PUC's approval of the proposed Plan is essential for the Company to continue maintaining a safe, reliable, and cost-effective electric distribution system for its Rhode Island customers.

Q. Does this conclude your joint testimony?

A. Yes, it does.

2021-2023
SRP 3-Year Plan

SYSTEM RELIABILITY PROCUREMENT

2021-2023 THREE-YEAR PLAN

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Appendices

Table of Terms

Term	Definition
3V0	Ground Fault (or Zero Sequence) Overvoltage
AESC	Avoided Energy Supply Components
AMF	Advanced Metering Functionality
Approximate Value	The estimated net present value of deferring the wires investment for the required timeframe.
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
BTM	Behind-the-Meter
Capex	Capital expenditure
CEM	Customer Energy Management
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CRM	Cost Recovery Mechanism
CSA	Construction Service Agreement
C-Team	(EERMC) Consultant Team
DER	Distributed Energy Resource
DG	Distributed Generation
Division	Division of Public Utilities and Carriers
DPAM	Distribution Planning and Asset Management
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effect(s)
DSP	Distribution System Planning
EE	Energy Efficiency
EE Plan	Energy Efficiency Program Plan
EEP	Energy Efficiency Program
EERMC	Energy Efficiency and Resource Management Council
EPC	Engineering, Procurement, and Construction
EPS	Electric Power System
ESA	Energy Service Agreement
ESS	Energy Storage System
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
Framework	Rhode Island Docket 4600 Benefit-Cost Framework
FTE	Full-Time Employee/Equivalent
FTM	Front-of-the-Meter
GHG	Greenhouse gas
GMP	Grid Modernization Plan
ISO	Independent Systems Operator

Term	Definition
ISO-NE	ISO New England Inc.
ISR	Infrastructure, Safety and Reliability Plan
kW	Kilowatt
kWh	Kilowatt-hour
LCP	Least-Cost Procurement
MW	Megawatt
MWh	Megawatt-hour
NECEC	Northeast Clean Energy Council
NERC	North American Energy Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPA	Non-Pipeline Alternatives
NPV	Net Present Value
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
OER	Office of Energy Resources
Opex	Operational expenditure
PIM	Performance Incentive Mechanism
Portal	Rhode Island System Data Portal
PST	Power Sector Transformation
PUC	Public Utilities Commission
PV	Photovoltaic
RD&D	Research, Design, and Development
REC	Renewable Energy Credits
REG	Renewable Energy Growth
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RI NWA BCA Model	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model
RI NWA BCA Model TRM	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Technical Reference Manual
RI Test	Rhode Island Benefit-Cost Test
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standards
SME	Subject Matter Expert
SO_2	Sulfur Dioxide
SRP	System Reliability Procurement
T&D	Transmission and Distribution
TWG	Technical Working Group
VVO	Volt-VAR Optimization

2021-2023 SYSTEM RELIABILITY PROCUREMENT THREE-YEAR PLAN

1. Executive Summary

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

The role of National Grid[1] with respect to SRP is to identify potential Non-Wires Alternative (NWA) and Non-Pipeline Alternative (NPA) opportunities, to source viable alternative solutions that address system needs and defer, reduce, or remove the need for distribution wires and pipes investments, and to support projects and programs that enable such activity.

The Company summarizes the rulings requested of the Rhode Island Public Utilities Commission (PUC) in the table below.

Table 1: Summary of Requested Rulings for SRP in 2021-2023

SRP Section	SRP Initiative/Proposal	Requested Ruling
5	SRP Funding Mechanism	The Company requests the PUC approve the Company's proposal that operational expenditure (opex)-type SRP investments be funded through the System Benefit Charge, or Energy Efficiency (EE) Charge, on customers' bills.
5	SRP Funding Mechanism	The Company requests the PUC approve the Company's proposal that capital expenditure (capex)-type SRP investments be filed and proposed in an SRP Investment Proposal.
6	SRP Performance Incentive Mechanism	The Company requests the PUC approve the Company's proposed performance incentive mechanism (PIM) for calendar years 2021 through 2023.
7.2	NWA Screening Criteria	The Company requests the PUC approve the proposed NWA screening criteria for Rhode Island as detailed in Table 5 for calendar years 2021 through 2023.

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

SRP Section	SRP Initiative/Proposal	Requested Ruling
8	NPAs in System Planning	The Company requests the PUC approve the development plan for the Non-Pipeline Alternatives program in calendar years 2021 through 2023.
12	SRP Timeline: SRP Investment Proposals	The Company requests the PUC rule on SRP Investment Proposals within 60 days of filing.
12	SRP Timeline: Year-End Reports	The Company requests the PUC approve the annual reporting plan for SRP Year-End Reports for calendar years 2021 through 2023.

The Company summarizes the anticipated funding requests and their cost recovery mechanisms (CRM) for 2021 through 2023 in the table below. The Company estimates that the stated incremental costs will be required in 2021 through 2023 to implement the projects and initiatives detailed in this Plan. Please note that the costs stated for calendar years following 2021 are informative to detail potential future costs. These anticipated costs could change in subsequent SRP Investment Proposals, based on the finalized proposal made in a specific year and given changes in system load demand, need for increased market engagement, or other activity.

Table 2: Summary of Anticipated 2021-2023 SRP Funding Requests

SRP Section	SRP Initiative/Proposal	CRM	CY 2021	CY 2022	CY 2023
6	SRP PIM	EE Charge	TBD	TBD	TBD
7	NWAs in System Planning	TBD	TBD	TBD	TBD
8	NPAs in System Planning	TBD	TBD	TBD	TBD
9	Rhode Island System Data Portal	EE Charge	$0	$0	$0
10	SRP Market Engagement	EE Charge	$0	$0	$0
		Total	**$0**	**$0**	**$0**

Please note that the cells that state "TBD" in Table 2 indicate unknowns because SRP plan and project development during future years will determine applicable funding requests for those items. Also note that the CRM for NWAs and NPAs is to be determined in the proposal stage, based on the specific solution's ownership model. Funding requests and CRM will be proposed and detailed in the respective SRP Investment Proposal filing for each NWA and NPA project.

Please note that no new enhancements or new work are currently planned for the Rhode Island System Data Portal (Portal) and the SRP Market Engagement program and that additional, incremental costs for these programs are therefore expected to be $0 for calendar years 2021 through 2023, as detailed in Sections 9 and 10, respectively.

The commitments included in the 2021-2023 SRP Plan are summarized in the following table. These commitments do not require additional, incremental SRP funding because they are actions covered by the work of full-time employees (FTEs).

Table 3: Summary of 2021-2023 SRP Commitments

SRP Section	SRP Commitment
7	The Company plans to continue analyzing its current NWA screening and development processes to determine how NWAs might be best considered as both complete and partial solutions.
8	The Company commits to developing the NPA Program parts over calendar years 2021 to 2023 and to providing an initial NPA Program, as detailed in Section 8.2, in the SRP 2023 Year-End Report filing. The Company commits to engaging with stakeholders to discuss and understand opportunities and challenges regarding NPAs throughout development of the NPA Program and its integral parts.
8.2	The Company intends to engage stakeholders continually throughout the development of the NPA program over the next three years via SRP TWG meetings. The Company intends stakeholders to be engaged during the development of specific program parts, as detailed in the figure above and the following program part descriptions.
8.2	The Company commits to produce a detailed initial NPA Program at the end of the 2021-2023 SRP Three-Year Plan cycle.
11	The Company recognizes that improved synchronization between SRP and Power Sector Transformation (PST), the Energy Efficiency Program Plan (EE Plan), the Infrastructure, Safety and Reliability (ISR) Plan, the Renewable Energy Growth (REG) Program, the Grid Modernization Plan (GMP), and the Advanced Metering Functionality (AMF) Business Case is necessary and intends to maintain and improve coordination between these filings.
11	Therefore, the Company commits to continued stakeholder engagement and continued participation in enhanced discussions regarding SRP, NWA, and related policy and programs with stakeholders.

SRP Section	SRP Commitment
11.1	The Company will commit to maintaining alignment between SRP and AMF with regard to the AMF Data Governance and Management Plan and will participate in future collaborative discussions about data access and security.

The proposals and information the Company presents in this SRP Plan advance Power Sector Transformation (PST)[2] goals, align with Docket 4600[3] principles, are coordinated with the Company's other programs and filings, and adhere to Least-Cost Procurement (LCP) law.

[2] "Power Sector Transformation Initiative." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island Office of the Governor Gina M. Raimondo, 8 Nov. 2017, www.ripuc.ri.gov/utilityinfo/electric/PST_home.html.

[3] "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.

2. Introduction

The Company is pleased to submit this 2021-2023 System Reliability Procurement Three-Year Plan (Plan) to the PUC. This Plan has been developed by National Grid through an iterative process with the SRP Technical Working Group (the SRP TWG).[4][5]

This Plan is being jointly submitted as a Stipulation and Settlement (Settlement) between Acadia Center, the Division of Public Utilities and Carriers (Division), the Energy Efficiency and Resource Management Council (EERMC), Green Energy Consumers Alliance, the Office of Energy Resources (OER), the Northeast Clean Energy Council (NECEC), and National Grid (collectively, the Parties). This Plan addresses a range of topics discussed by members of the SRP TWG regarding the Company's Plan for calendar years 2021 through 2023.

National Grid respectfully seeks approval of this Plan and its integral proposals in accordance with the guidelines set forth in Section 4 of the LCP Standards.

[4] Members of the SRP TWG presently include the Company, Acadia Center, the Division, Green Energy Consumers Alliance, OER, NECEC, several EERMC members, and representatives from the EERMC's Consultant Team (EERMC C-Team).

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

3. Regulatory Basis for System Reliability Procurement

This SRP Plan is submitted in accordance with the Least-Cost Procurement law, R.I. Gen. Laws § 39-1-27.7,[6] the basis for which is the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006[7] (the 2006 Act) and as amended in May 2010. The 2006 Act provides the statutory framework for least-cost procurement, including system reliability, in the State of Rhode Island. The 2006 Act provides a unique opportunity for Rhode Island to identify and procure cost-effective customer-side and distributed resources with a focus on alternative solutions to the standard supply and infrastructure options. These alternative solutions may deliver savings to customers by deferring or removing the need for distribution system investment and improving overall system reliability over time.

This SRP Plan is also submitted in accordance with the Rhode Island PUC's revised "Least-Cost Procurement Standards," which the PUC approved and adopted pursuant to Order No. 23890 in Docket No. 5015 (LCP Standards).[8] The LCP law, R.I. Gen. Laws § 39-1-27.7, requires standards and guidelines for system reliability. On July 23, 2020 in Docket 5015, the PUC unanimously approved the revised standards for system reliability, finding that the standards were consistent with the policies and provisions of R.I. Gen. Laws § 39-1-27.7.1(e)(4),(f) and R.I. Gen. Laws § 39-1-27.7.3.

> ***§ 39-1-27.7. System reliability and least-cost procurement. –*** *Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.*[9]

The LCP law further states that SRP resources are intended to include, but are not limited to, the following:

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

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

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

[8] "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.

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

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

SRP resources include, in part, NWA and NPA investments. Section 4.4.A of the LCP Standards requires that the Company identify distribution projects that meet certain screening criteria for potential NWAs or NPAs that reduce, avoid, or defer distribution wires investments. See Section 7 for detail regarding NWAs and Section 8 for detail regarding NPAs.

Sections 4.4 and 4.6 of the LCP Standards further require the Company to submit, by November 21, 2020 and triennially thereafter, an SRP Three-Year Plan that includes, among other information, the proposed Performance Incentive Mechanism (PIM) for SRP, proposed screening criteria for SRP investments, strategies that enhance procurement of SRP investments, the general procurement process for SRP, the evaluation process and criteria for SRP investments, and a proposed annual reporting plan for implementation updates of SRP investments. For additional discussion on the criteria for NWA analysis, please see Section 7.

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

3.1 Cost Test

In accordance with Section 1.3.B of the revised Standards, the Company adheres to the Rhode Island Benefit-Cost Test (RI Test) for all SRP investment proposals. The Company has developed the Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model (RI NWA BCA Model), which is a derivative of the RI Test and utilizes the same Rhode Island Docket 4600 Benefit-Cost Framework (Framework), to more accurately assess NWA opportunities benefits and costs. Please see Appendix 3 for the RI NWA BCA Model.

The shift to using the RI NWA BCA Model has been a positive development for SRP. Per the LCP Standards, this specialized derivative of the RI Test is created using the RI Framework and accounts for applicable policy goals, PUC orders, regulations, guidelines, and other policy directives; accounts for all relevant, important aspects of the SRP and NWA programs; is symmetrical by including both costs and benefits for each relevant type of impact; is forward-looking by capturing the benefit-cost analysis over the life of the investment; and is transparent in its application and calculation.

Accounting for all costs and benefits associated with System Reliability Procurement provides a more robust accounting of the societal benefits that SRP investments deliver to electric customers, the state, and society.

The cost test and cost-effectiveness analyses of SRP investments use avoided cost impact factors developed by Synapse Energy Economics as part of the "Avoided Energy Supply Components in New England: 2018 Report" (2018 AESC Study), sponsored by New England's electric and gas energy efficiency program administrators.[10] The study utilizes state level avoided costs to reflect current and expected market conditions and are highly influenced by the cost of fossil fuels and expectations about ISO-NE's forward capacity market. Where applicable, the company utilizes site-specific calculations to augment the state level data. The cost-effectiveness analyses also include estimates of economic benefits applicable to System Reliability Procurement.

Project-specific transmission and distribution capacity values are also included. The company has developed a deferral calculator that utilizes the location-specific wires solution expected cost, related operations and maintenance (O&M) costs, depreciation, and revenue requirements over the course of the expected lifetime of a wires solution. A distribution deferral value is obtained by delaying the need date for a wires solution.

The RI NWA BCA model will be continually reviewed by internal cross-functional teams and, in alignment with the SRP Year-End Report filings, externally on an annual basis by the EERMC Consultant Team (EERMC C-Team), Division, and the PUC.

The Company will use the RI NWA BCA Model, as detailed in Section 7.4 and Appendix 3, for assessing Rhode Island NWAs. Correspondingly, the RI NWA BCA Model Technical Reference Manual (RI NWA BCA Model TRM) is detailed in Appendix 4.

3.2 Cost-Effective

Cost-effectiveness is assessed at the program/project level in SRP. A cost-effectiveness analysis will be completed for potential NWA solutions. The SRP investment will be considered cost-effective if the benefit-cost ratio (BCR) for the resource is greater than 1.0. Utilizing the cost test as detailed in Section 3.1, NWA options will be compared to each other and the wires option. This comparison will be utilized during the NWA evaluation process outlined in Section 7.4. Note that the costs of carbon dioxide (CO_2) mitigation, as imposed by the Regional Greenhouse Gas Initiative (RGGI)[11], and other utility system costs are accounted for in the RI NWA BCA Model

[10] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.
[11] "State Statutes & Regulations - Rhode Island." *The Regional Greenhouse Gas Initiative*, RGGI, Inc., www.rggi.org/program-overview-and-design/state-regulations.

as detailed in Table 4. The Company plans to demonstrate cost-effectiveness for any specific projects by inclusion of the RI NWA BCA Model results in each SRP Investment Proposal filing. The benefit-cost analysis (BCA) methodology for SRP proposals is consistent with the language in the LCP Standards Section 1.3.C and Docket 4600 Framework.

Table 4. Summary of RI Test Benefits and Costs Applicability

RI Test Category	Docket 4600 Category	SRP Program	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	Renewable Energy Credits (REC) Value (Power System Level)	X	
	Greenhouse Gas (GHG) Compliance Costs (Power System Level)	X	
	Environmental Externality Costs (Power System Level)	X	
Demand Reduction Induced Price Effects (DRIPE)	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, waste water (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	

RI Test Category	Docket 4600 Category	SRP Program	Notes
	Customer empowerment and choice (Customer Level)	O	
	Utility low income (Power System Level)	O	
	Non-participant rate and bill impacts (Customer Level)	X	
Non-Embedded GHG Reduction Benefits	GHG Externality Cost (Societal Level)	X	
Non-Embedded Nitrogen Oxides (NOx) Reduction Benefits	Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)	X	
Non-Embedded Sulfur Dioxide (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 Resource (DER) 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 NWAs in the SRP program. (1) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e. NWAs or NPAs). (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 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)

3.3 Reliable

SRP investments must always meet the system need or support the sourcing of solutions that are evaluated to meet the system need. When procuring an SRP investment, such as an NWA solution, the following aspects are considered during NWA bid evaluation: safety, level of availability given a contingency or peak load event (e.g. market participation), level of communication uptime, maintenance, fuel availability, response time, and level of customer engagement as applicable, in additional to the technical and functional requirements. Every NWA bid proposal is compared with the other competing NWA bid proposals, as detailed in Section 7.4, and the Company's wires option to determine that the potentially viable primary NWA option meets the technical requirements and does not detrimentally impact the customer. These aspects indicate how a proposed SRP investment aligns with the reliable requirement in accordance with Section 1.3.D of the revised Standards.

3.4 Prudent

SRP investments consider cost deferral, the overall timeline of solution implementation, and the lifetime of any procured solution. SRP investments seek to produce synergy savings by deferring, reducing, or removing costs that would otherwise be borne via ISR investments. When procuring an SRP investment, SRP proposal evaluation includes schedule criteria such as meeting the need date, project milestones, and timing of project planning and permitting. Also, investment risk is addressed in NWA proposal evaluation, as detailed in Section 7.4. Additionally, for solutions that involve physical assets, any applicable ratings degradation of the asset is considered and factored in to the solution procurement. Furthermore, please see Section 5 for detail on the effective use of available funding sources; note that funding requests and bill impacts are detailed for each specific proposal in the respective SRP Investment Proposal filings. These aspects indicate how a proposed SRP investments align with the prudent requirement in accordance with Section 1.3.E of the revised Standards.

3.5 Environmentally Responsible

While maintaining an agnostic view with technology type, SRP investments assess , as part of their evaluation criteria as detailed in Section 7.4, consideration of customer impacts, zoning considerations, GHG emissions, public health impacts, and the aesthetic, economic, acoustic, and general environmental impacts. SRP investments also adhere to Docket 4600 framework, overall and specific to environmental impacts. These aspects indicate how a proposed SRP investments align with the environmentally responsible requirement in accordance with Section 1.3.F of the revised Standards.

3.6 Lower than the Cost of the Best Alternative Utility Reliability Procurement

In accordance with Section 1.3.H of the LCP Standards, SRP investments are compared with the cost of the best alternative Utility Reliability Procurement. This includes comparison between the alternative non-wires or non-pipes option and the standard option for applicable cost categories enumerated in the Rhode Island Docket 4600 Benefit-Cost Framework or, at a minimum, in the Total Resource Cost Test[12], as detailed in Section 3.1 and 3.2 and through the evaluation process as detailed in Section 7.4.

[12] "Docket No. 4443 - RI Energy Efficiency and Resource Management Council (EERMC) - Proposed Energy Efficiency Savings Targets for National Grid's Energy Efficiency Procurement for the Period 2015 - 2017 Consistent with Least Cost Procurement (Filed 9/17/13)." *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.

4. SRP Program Design and Planning Principles

The SRP program is designed to achieve optimal cost-effectiveness for the electric and natural gas systems and for Rhode Island customers, while maintaining the safety and operational reliability of such systems and integral assets.

The SRP program and its constituent investments are planned in accordance with LCP law and the LCP Standards as detailed in Section 3, the guidance and process aligned with electric distribution planning as detailed in Section 7 and the in-development guidance and process with gas distribution planning as proposed in Section 8, and in coordination with other Company programs and initiatives as detailed in Section 11.

Areas of focus for National Grid in the SRP program for calendar years 2021 through 2023 include the following:

- Identification of system needs for the gas and electric systems
- Identification of potential NWA opportunities
- Identification of potential NPA opportunities, including NPA pilot opportunities, as the NPA program is developed
- Development of National Grid's NPA program
- Continued and improved market engagement, including sourcing potential NWA and NPA solutions
- Continued vendor stakeholder and SRP stakeholder engagement
- Continuous refinement of NWA Deferral Value calculation
- Continuous program and process improvement

Consistent with R.I. Gen. Laws § 39-1-27.7, SRP intends to engage the market to resolve electric and natural gas system needs with the goal to reduce costs to customers in Rhode Island through cost-effective, reliable, prudent, and environmentally responsible avenues. SRP pursues this need and goal by engaging with the market via SRP Market Engagement, vendor outreach, and the Portal and by sourcing targeted alternative solutions in the form of NWAs and NPAs.

SRP incrementally contributes to state energy policies and goals for the electric and natural gas systems through its investments working in concert, namely SRP Market Engagement and the Portal with NWA and NPA solutions. SRP Market Engagement and the Portal enable third-party solution providers to more easily access available information about National Grid's electric distribution system and SRP opportunities in Rhode Island. This information helps third-party solution providers to better site DER projects and to engage with the Company's NWA and NPA opportunities. Correspondingly, successful NWA and NPA solutions help to reduce costs to customers, increase environmentally responsible energy resources, potentially increase renewable energy resources, and maintain or even improve system safety, reliability, and resiliency.

NWA and NPA solutions support Rhode Island state goals and initiatives, which include Executive Order 20-01[13] that mandates "to meet one hundred percent (100%) of the state's electricity demand with renewable energy resources by 2030", Executive Order 19-06[14] that mandates the path forward for Heating Sector Transformation, the integral components of Power Sector Transformation, and the integral components of the Resilient Rhode Island Act of 2014[15].

[13] R.I. Executive Order No. 20-01 (Jan. 17, 2020), https://governor.ri.gov/documents/orders/Executive-Order-20-01.pdf.

[14] R.I. Executive Order No. 19-06 (July 8, 2019), https://governor.ri.gov/documents/orders/Executive%20Order%2019-06.pdf.

[15] "CHAPTER 42-6.2 Resilient Rhode Island Act of 2014 – Climate Change Coordinating Council." *Chapter 42-6.2 - Index of Sections*, State of Rhode Island General Assembly, 2014, http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM.

5. SRP Funding Mechanism

The Company proposes to fund the projects and initiatives included in SRP Investment Proposals through the applicable cost recovery mechanism.

For SRP investments composed of operational expenditure (opex), the Company proposes that such investments be filed and proposed in an SRP Investment Proposal. The Company also proposes that such investments be funded through the System Benefit Charge, or Energy Efficiency (EE) Charge, on customers' bills. Such opex-type SRP investments may include third-party owned and operated NWA projects, new enhancements to the Rhode Island System Data Portal, or SRP market engagement work.

For SRP investments composed of capital expenditure (capex), the Company proposes that such investments be filed and proposed in an SRP Investment Proposal. The Company also proposes that specific capex tracking factors would be used to track funding allocated to such capex-based SRP investments. This capex tracking factor would be separate from the SRP Opex Factor that is a component of the EE Charge. Such capex-type alternative investments may include Company-owned and operated NWA or NPA projects.

All funding requests made in SRP Investment Proposals are factored into the respective SRP cost recovery mechanism. For opex-type SRP investments this would be the SRP Opex Factor, or the "Proposed SRP Opex Factor per kWh" value, which is a component of the EE Charge on customers' bills. The proposals and funding requests in SRP Investment Proposals are not complemented by or funded through other Company programs or plans.

The SRP Program itemizes the recommended work activities for each calendar year by project/program and provides budgets for operation and maintenance expenses for the respective SRP projects and programs. After the end of each calendar year, the Company balances SRP funds by comparing the SRP Program's projected expense levels used for establishing the revenue requirement to actual or allowed investment and expenditures on a cumulative basis and reconciles the revenue requirement associated with the actual investment and expenditures to the revenue billed from the rate adjustments implemented at the beginning of each calendar year.

Please note that administrative costs for SRP plan development and stakeholder meetings are covered by the work of FTEs and are included in the current rate case under Docket 4770.[16] Only additional, incremental costs for plan implementation of proposed projects and programs are included in SRP funding requests.

[16] "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.

6. SRP Performance Incentive Mechanism

This section details the SRP Performance Incentive Mechanism to advance LCP goals.

The Company and the Parties have agreed on savings-based metrics for the Company to earn incentives on work completed through SRP in years 2021 through 2023.

The Company will be able to earn savings-based incentives for DER, targeted EE measures, or targeted demand response (DR) programs that are installed or implemented as a result of SRP Requests for Proposals (RFPs). The Company will be obligated to demonstrate that DERs, targeted EE, or targeted DR were installed or implemented as a result of SRP investments. This demonstration would require:

1. The project contract between the solution provider and the Company, and
2. Confirmation that the SRP solution was installed by the in-service need date of the SRP opportunity, and
3. Measured output at the feeder during peak hours showing the specific investment's contribution to mitigating or eliminating the specified system need.

For the Company to earn savings-based incentives on such SRP investments, the investments must be deemed cost-effective according to the Rhode Island cost-effectiveness framework established in the Commission's Docket 4600 Guidance Document.

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

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

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

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

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

The savings-based incentive mechanism would be applied to the net benefits of the SRP project(s) proposed in SRP Investment Proposals, as well as any projects installed and marketed as a result of the other SRP initiatives proposed in the SRP Investment Proposals, to the extent they meet the criteria outlined in this section and the projects or initiatives result from RFPs.

The proposed savings-based incentives for specific and implemented SRP projects would be filed annually in an SRP Investment Proposal following year-end analysis of the SRP project's performance measurement. The savings-based incentive proposal for a specific SRP project would detail the requested incentive value, the corresponding calculation, and would be based off the prior year's actual solution performance measurements.

The Company requests approval of the proposed PIM as detailed in this section for calendar years 2021 through 2023.

7. NWAs in System Planning

This section details the Company's Non-Wires Alternative program in Rhode Island.

7.1 Definition of NWA

The definition and requirements of NWAs are as follows:

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

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

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

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

The maximum amount payable for NWA resources will be an annualized amount of the Approximate Value for the NWA opportunity. This Approximate Value is a net present value (NPV) calculated from 100% of the deferral value of the otherwise-needed localized wires investment option, which by default are location-based avoided costs. The 100% rate is the application of the Rhode Island Locational Incentive to provide greater value to Rhode Island customers. The rate was previously pegged at 60% of the deferral value, as described in the 2019 SRP Report; however, the Company has experienced reduced market engagement following this derated incentive. The Approximate Value is stated in NWA RFPs to help inform third-party solution providers whether their NWA solution bid is cost-effective for the need. Any contracts to procure NWAs would have to be approved by the PUC, as required for all non-tariff contracts.

7.2 Screening Criteria for NWA

The screening criteria for potential NWA opportunities are as follows:

Table 5: Screening Criteria for NWA Opportunities

Criteria Type	Criteria Requirement
Project Type Suitability	Project types include Load Relief and Reliability.[17] The need is not based on Asset Condition. Other types have minimal suitability and will be reviewed as suitability changes due to State or Federal policy or technological changes. If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.
Timeline Suitability	Start date of system need is at least 24 months in the future.
Cost Suitability	Cost of wires option is greater than $1M.

Additionally, by the Company's discretion, National Grid may pursue a project that does not pass one or more of these criteria if there is reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

Project types for potentially viable NWA include load relief and reliability because other need types are dependent on resolving equipment degradation, such as with asset condition, upgrading substations and feeders with Volt-VAR Optimization (VVO), upgrading protective circuitry, or other needs that fall outside of the scope of SRP and NWA. Asset condition work and protective circuitry upgrades are standard distribution planning activities and would fall within ISR. VVO upgrades are part of grid modernization activities and would therefore fall within the purview of the Grid Modernization Plan (GMP). Other system needs may also be addressed through SRP so long as the need is not based on asset condition, and as determined to be potentially feasible, technically or economically, by the Distribution Planning and Asset Management (DPAM) and NWA teams. Additionally, NWA projects should not exceed 20% of the total load in the area of the defined need because a significant minority or a majority of load, and therefore customers, would lose power and be put at risk should the NWA fail to operate for any event call.

Timeline suitability is set at 24 months based on the development and implementation timeframe needed for most projects and project types and to align with ISR and distribution planning timeframes.

Cost suitability is set at one million dollars based on National Grid's experience to date illustrating that any system need with a wires option value less than $1M does not produce economically

[17] For definition of reliability, see "Docket 3628: Proposed Service Quality Plan." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2004, www.ripuc.ri.gov/eventsactions/docket/3628page.html.

viable NWA opportunities and that the market does not find such NWA opportunities to be fiscally prudent for their goals and policies.

These screening criteria are applied by the DPAM team to all electric system needs that arise through planning analysis and system assessment. Such screening criteria is utilized during Initial System Assessment, as detailed in Section 7.3.

The Company requests approval of the proposed NWA screening criteria for Rhode Island as detailed in Table 5 for calendar years 2021 through 2023.

7.3 NWA Planning Process and Integration with Electric System Planning

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

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

The Company identifies and screens potential NWA opportunities through the following high-level sequential process once a system need is identified or an area study is initiated:

1. <u>Scoping</u>

   The DPAM team develops a scope for a specific system need or a scope that details the boundaries and concerns of an area study. Planning criteria, Company standards, and forecasts are inputs to the Scoping stage. The Rhode Island peak forecasting reports and redacted area studies are posted on the "Company Reports" tab of the Rhode Island System Data Portal.[18]

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

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

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

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

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

3. Engineering Analysis

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

Additionally, the potential for targeted EE and targeted DR sourced from internal Company programs is assessed at this stage, if timing for the system need allows, to determine whether they are viable components to include as part of an NWA solution. Formal evaluation of the internally-sourced targeted EE or targeted DR proposals is handled at the same time external bid proposals are evaluated.

System needs that are sufficiently out in the future are re-analyzed to determine whether the technical and economic requirements have changed in a way that allows an NWA option to be potentially feasible, per the NWA screening criteria. Timing of re-evaluation is established within and determined by the specific area study.

4. Plan Development

Plan development is the stage when wires options and non-wires options are developed.

To determine whether a potential NWA opportunity is feasible for an electric grid need, the DPAM team screens distribution projects with the criteria listed in Section 7.2 of this Plan, which are aligned with the Company's internal planning document. Feasibility is based on these screening criteria, which cover technical, economic, and timing factors.

These NWA screening criteria are applied to an identified electric grid need and resulting potential NWA opportunities are investigated.

The NWA team develops the NWA RFP, sends the RFP to market, and receives and evaluates NWA bid responses during this stage. National Grid maintains a technology-agnostic approach with NWA RFPs. Please see Section 10.1 for the market engagement channels the Company utilizes for NWA outreach.

The NWA team analyzes and evaluates the NWA option in parallel to the wires option, which is developed by the DPAM team.

If the DPAM team determines that an NWA opportunity is technically and economically feasible according to the NWA screening criteria, the NWA team then gathers relevant engineering information from the DPAM team and develops an NWA RFP. This engineering information is derived from the engineering analysis. This NWA RFP is then published to the market for third-party solution providers to bid on. The NWA team then evaluates any bids received and selects the most suitable bid for the NWA opportunity, as detailed in Section 7.4. The NWA team proposes the winning NWA solution to the DPAM team as the NWA option for the specified electric grid need.

5. <u>Select Recommended Plan</u>

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

If an NWA option is selected as the solution for the electric grid need, then the NWA solution is proposed through the next SRP Investment Proposal, as detailed in Section 12.

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

If the NWA option is determined to be more cost-effective than the wires option but is nonetheless not selected, the Company will then provide a detailed explanation for the selection of the wires option.

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

For reference on timing of the NWA review process and possible inclusion in a specific year's Electric ISR Plan please see Figure 1 and Figure 2, which illustrate the Distribution Planning Study Process and NWA Procurement Process, respectively. The Distribution Planning Study Process outlines the major steps and study-based inputs in the overall area study process.

Please note that capital infrastructure projects that have passed screening for potential NWA opportunities will not be advanced in the Electric ISR Plan unless they have been fully evaluated for NWA. Also note that the Company reevaluates the potential for an NWA opportunity for a system need only if the technical and economic requirements of the system need and corresponding wires option have changed significantly and if the timeframe allows according to the screening criteria. These reevaluation limits are set to prevent causing market and bidder exhaustion by persistently cycling through the same potential NWA opportunities that are ultimately deemed unviable by the market.

Please note that projects that have had the potential for NWA screened out, including any follow-up re-evaluation or re-screening of the system need, are progressed through the wires option pathway. These wires options are not proposed in an Electric ISR Plan for implementation until the wires option is fully developed.

A general example of this process from the perspective of NWA options analysis is as follows:

- DPAM identifies a system need.
- DPAM screens the system need through the NWA screening criteria detailed in Table 5.
    - If the system need fails any of the NWA screening criteria, then the Company pursues the wires option.
    - If the system need passes the NWA screening criteria, then the Company proceeds with NWA options analysis.
- The NWA project manager (PM) gathers engineering data and the system need technical requirements from DPAM.
- The NWA PM assesses the potential for internally-sourced targeted EE and targeted DR from National Grid's EE and DR Programs. The NWA PM requests an internal targeted EE/DR option from the Customer Energy Management (CEM) team.
- The NWA PM develops the RFP for the NWA opportunity.
- The Procurement team sends the NWA RFP out to market and engages the market through the channels detailed in Section 10.1.
- Third-party bid proposals are received. The NWA opportunity is now in proposal review, as illustrated by Figure 2.
- The review team comprised of subject matter experts (SMEs) and internal stakeholders evaluates all bid proposals received with the NWA evaluation criteria detailed in Table 7, including the internal targeted EE/DR option from the CEM team.
    - If no bid proposals pass NWA evaluation, and are therefore deemed not viable, the Company pursues the wires option.
    - If at least one bid proposal passes NWA evaluation, then the Company continues with NWA proposal evaluation.
- Additional step, Rhode Island only: the NWA PM and DPAM lead assess the cost-effectiveness of the prime NWA option to the prime wires option, which was developed and assessed by DPAM in parallel to the NWA option developed and evaluated by the NWA team. This assessment is in line with LCP Standard 1.3.H, as referenced in Section 3.6.

  - If the NWA option is determined to be more cost-effective than the wires option, then the NWA option is selected given that it already passed all NWA evaluation criteria.
  - If the NWA option is determined to not be more cost-effective than the wires option, then the wires option is selected.
- If the technical and economic requirements of the system need and corresponding wires option change significantly following initial NWA options analysis and the timeframe allows according to the screening criteria, then the DPAM team notifies the NWA team and the NWA PM begins a new NWA options analysis.
- If the NWA option passed all NWA evaluation criteria and the LCP 1.3.H requirement, then the Company awards the NWA project to the winning bid and proceeds with contract negotiation with the respective bidder.
- Following contract negotiation, the Company proposes the NWA project in an SRP Investment Proposal filing.
- If the NWA project proposal is approved by the PUC, then the Company coordinates with the bidder to start NWA project implementation.

The Company plans to continue analyzing its current NWA screening and development processes to determine how NWAs might be best considered as both complete and partial solutions.

Figure 1: Electric Distribution Planning Study Process Flowchart

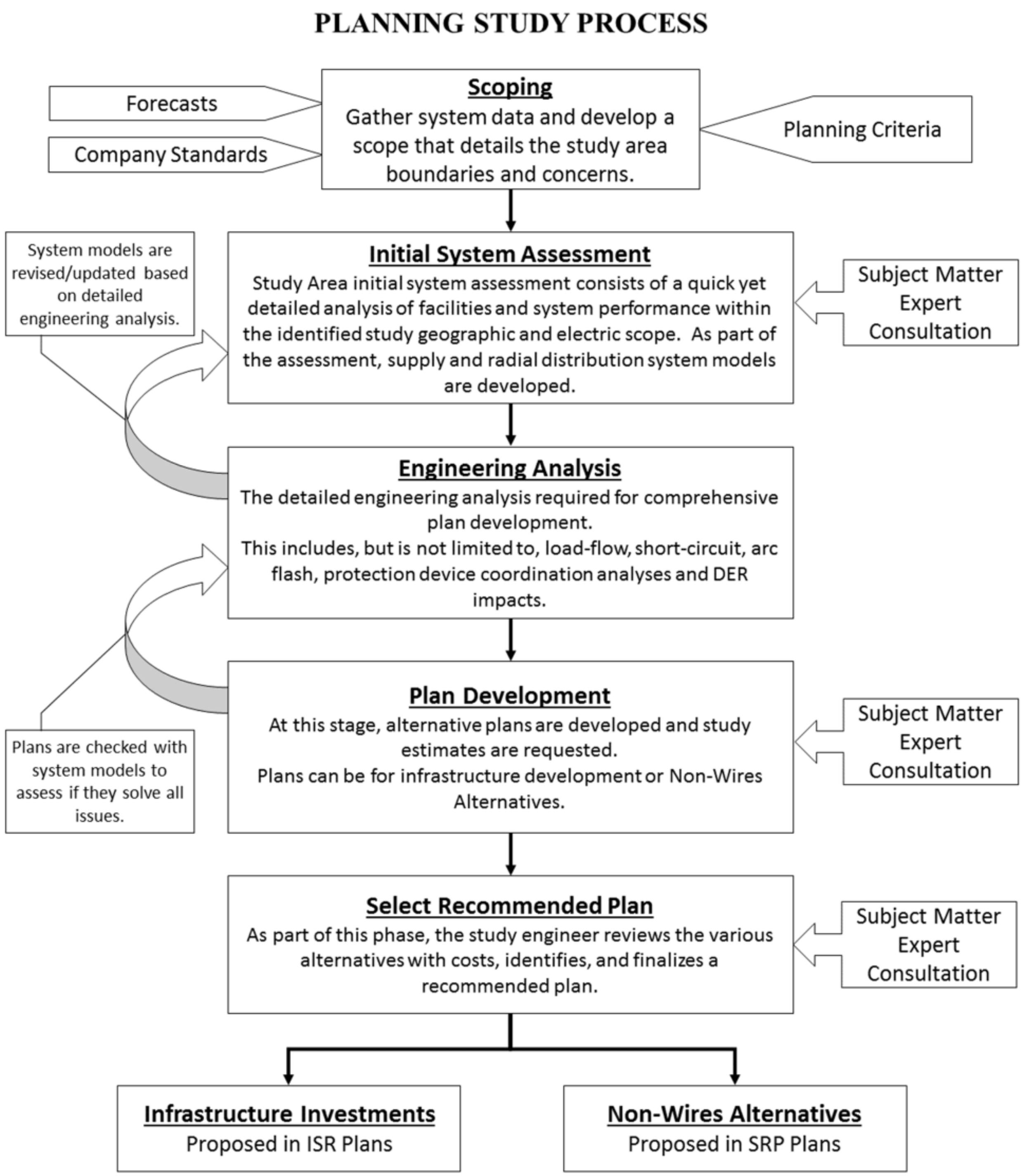
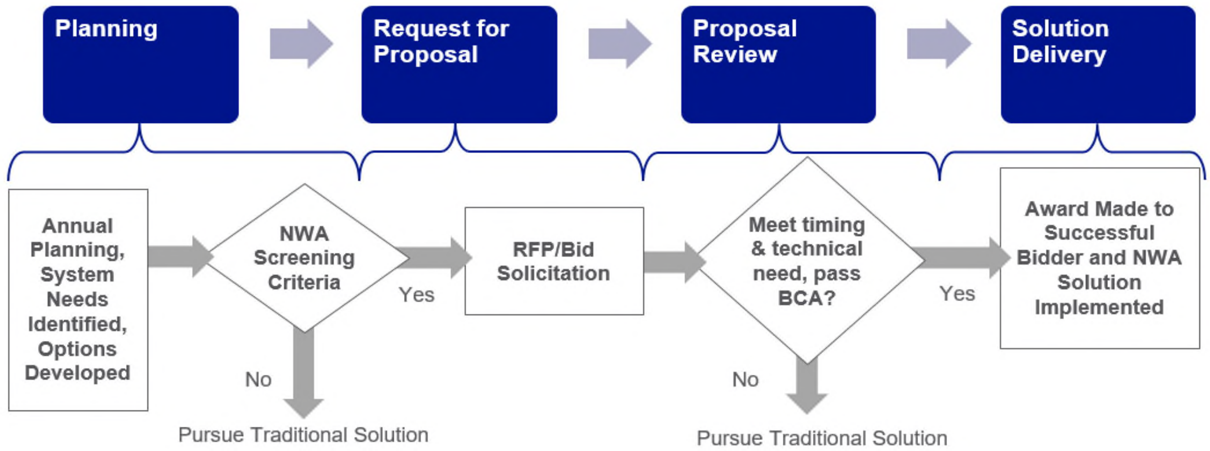


Figure 2: Overview of National Grid's NWA Procurement Process



7.4 NWA Evaluation Process

Following receipt of all bid proposals for an NWA opportunity, National Grid proceeds directly into the evaluation stage of the NWA process. This evaluation and review of submitted bid proposals is comprised of four rounds of evaluation, with each round based on a high-level screening, detailed technical review, detailed economic review, and final round selections, as detailed in the table and figure below. All bid proposals are evaluated in parallel through these four rounds.

Figure 3: National Grid NWA Evaluation Rounds

Table 6: National Grid NWA Evaluation Rounds Description

Round	Evaluation Focus
Round 1	Go/No-Go: preliminary BCA, bidder qualifications, technology type and maturity, schedule, engineering

Round	Evaluation Focus
Round 2	Detailed technical review: engineering, controls, communications and operations, permitting, schedule and milestones
Round 3	Detailed economic review: full BCA, credit rating assessment, financing structure, payment structure, additional included costs and incentives
Round 4	Final review of shortlisted bidders, winning bidder selection as applicable, contract negotiation

The “preliminary BCA”, as indicated in Round 1 in the table above, is to determine if the cost-effectiveness of the proposal is even somewhat feasible, it involves the initial proposed solution cost and applicable benefits based on technology. The “full BCA”, as indicated in Round 3 in the table above, includes the more complex factors, such as interconnection cost and any contract negotiation changes, and other factors that require deeper research to determine.

National Grid has developed and refined over several years rigorous NWA evaluation criteria to comprehensively assess NWA bid proposals. These evaluation criteria are applied to every single NWA bid proposal that National Grid receives. The criteria are equivalently applied for any solution approach or technology type. The criteria are also equivalently applied for any proposal source, whether from a third-party solution provider or from an internal National Grid team, such as an internally-sourced Company bid proposal for a targeted energy efficiency solution from National Grid’s CEM team.

Partial NWA opportunities are also assessed as an option. Partial NWAs are solutions that address part of a specified system need with the rest of the system need addressed by the wires option. A partial NWA effectively reduces the scope of infrastructure projects.

Factors that will influence the solutions that are chosen will include availability and reliability, viability and functionality, existing market conditions for the proposed technologies, societal and environmental impact, cost-effectiveness, safety and risk, flexibility, ability to meet the specific identified system need, bidder’s experience, and the ability for a solution proposal to pass the BCA. The NWA bid proposal that scores highest in total across all categories and meets the minimum criteria requirements (cost-effective, meets the technical need, and does not detrimentally impact the customer) is selected as the winning bid, as applicable. Additionally, in Rhode Island, the costs and cost-effectiveness are compared between the NWA options and the wires option, in alignment with LCP 1.3.H. The NWA evaluation categories are detailed and described in Table 7 below.

Table 7: National Grid USA Evaluation Categories for NWA Solution Proposals

Category	Description
Proposal Content & Presentation	Information requested has been provided by the bidder and is sufficiently comprehensive and well presented to allow for evaluation.
Developer Experience	The experience of the Bidder, any Engineering, Procurement and Construction (EPC) contractor, prime subcontractors and, if applicable, O&M operator or other entity responsible for the development, construction, or operation of the proposed solution.
Environmental	The Bidder's Proposal shall address Impacts including but not limited to acoustic, aesthetic, air and GHG emissions, water, and soil impacts, and permitting and zoning considerations.
Project Viability	The probability that the solution(s) associated with a Proposal can be financed and completed as required by the relevant agreement.
Functionality	The extent to which the proposed solution would meet the defined functional requirements and the ability to provide demand reduction during peak times and within the geographic area of need.
Technical Reliability	The extent to which the proposed type of technology and the equipment would meet the reliability need and can be integrated with utility operations including the ability to monitor and dispatch.
Safety	National Grid requires that the Bidders recognize safety is of paramount importance. Bidders will be required to provide safety information related to the proposed technology and information regarding safety history.
Customer and Socio-economic Impacts	The Bidder's Proposal shall address how the proposed technology impacts the customer in addition to temporary and permanent jobs to be created, economic development impacts, and property tax payments. National Grid also assesses public health and energy pricing impacts of each solution proposal.
Scheduling	The Bidder's Proposal shall include proposed timelines outlining milestones and providing sufficient details for each deliverable, including meeting the in-service need date.
Offer Price	The Bidder's Proposal shall be based on project-specific values and financing requirements.
Adherence to Terms	The extent to which the Bidder accepts National Grid's proposed Term Sheet will be taken into consideration. The RFP evaluation may impute an additional amount to Bidder's Proposal to reflect any proposed modifications to the non-price terms and conditions by the Bidder that result in National Grid incurring additional costs or risks. Redlines to the Term Sheet shall be provided by the Bidder as part of its Proposal for review by National Grid during the evaluation period.
Credit	Bidder's capability and willingness to perform all of its financial and other obligations under the relevant agreement will be considered by National Grid in addition to Bidder's financial strength, as determined by National Grid, and any credit assurances acceptable to National Grid that Bidder may submit with its Proposal.

7.5 Analysis of System Needs

Detail on system needs that meet the screening criteria, as detailed in Section 7.2, and that the Company has determined may produce a potentially viable NWA opportunity are summarized in the table in Appendix 2 and detailed in the sections below as follows:

7.5.1 Bonnet 42F1

The Bonnet 42F1 NWA opportunity, formerly called Narragansett 42F1 NWA, intends to provide load relief in the Town of Narragansett by deferring or removing the need for feeder line work and reconfiguration on the Bonnet 42F1 feeder. The Bonnet 42F1 system need was identified as part of the South County East Area Study.

The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Feeder 42F1 is projected to be loaded above summer normal ratings by 2024 and lacks useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town. The distribution system need can be addressed through SRP by implementation of an NWA solution that provides load reduction capability.

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

The Company issued an RFP for the Narragansett 42F1 NWA opportunity in calendar year 2018 and evaluated the submitted bid proposals from third-party solution providers in calendar year 2019. All NWA solution bid proposals submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

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

The Company will proceed with investigating alternate solution pathways, which may include: refining the parameters of the need, re-engineering the RFP, a Company-sourced proposal, a Company-owned solution, or a partial NWA. The Company is still actively seeking potential NWA solutions for this opportunity. If an NWA solution option is identified that passes all Company NWA evaluation criteria and meets all LCP criteria, then the Company will proceed to propose the NWA investment in an SRP Investment Proposal filing.

7.5.2 Bristol 51

The Bristol 51 NWA opportunity intends to provide load relief and address MWh violations in the Town of Bristol by deferring or removing the need for feeder line work and reconfiguration on the

Bristol 51F1, 51F2, and 51F3 feeders. The Bristol 51 system need was identified as part of the East Bay Area Study.

The Town of Bristol is mostly supplied by (3) 12.47 kV distribution feeders. Loading on the 51F1, 51F2, and 51F3 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded in the next ten years. Either more capacity must be added or load must be reduced in the town. The distribution system need can be addressed through SRP by implementation of an NWA solution that provides load reduction capability.

The Company expects that the Bristol 51 NWA timeframe will span nine years from 2022 to 2030, which is the maximum amount of time based on the current peak load forecast that the substation and feeder upgrade can be deferred with this solution. There is the potential for a partial or continued NWA solution following 2030 with the Bristol 51 NWA; however, this option has not been assessed at this time.

The Company issued an RFP for the Bristol 51 NWA opportunity in calendar year 2020. The Bristol 51 NWA bid proposals submitted to National Grid are currently in evaluation and review

If an NWA solution option is identified that passes all Company NWA evaluation criteria and meets all LCP criteria, then the Company will proceed to propose the NWA investment in an SRP Investment Proposal filing.

7.5.3 South Kingstown

The South Kingstown NWA opportunity intends to provide load relief in the Town of South Kingstown by deferring or removing the need for feeder line work and reconfiguration on the Peacedale 59F3 and Kenyon 68F2 feeders. The South Kingstown system need was identified as part of the South County East Area Study.

The western section of the Town of South Kingstown is supplied mostly by (3) 12.47 kV distribution feeders. Feeders 59F3 and 68F2 are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town. The distribution system need can be addressed through SRP by implementation of an NWA solution that provides load reduction capability.

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

The Company issued an RFP for the South Kingstown NWA opportunity in calendar year 2019 and evaluated the submitted bid proposals from third-party solution providers in calendar year 2019. All NWA solution bid proposals submitted to National Grid for this opportunity did not pass evaluation for a feasible solution.

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

The Company will proceed with investigating alternate solution pathways, which may include: refining the parameters of the need, re-engineering the RFP, a Company-sourced proposal, a Company-owned solution, or a partial NWA. The Company is still actively seeking potential NWA solutions for this opportunity. If an NWA solution option is identified that passes all Company NWA evaluation criteria and meets all LCP criteria, then the Company will proceed to propose the NWA investment in an SRP Investment Proposal filing.

8. Proposal for NPAs in System Planning

This section details the Company's plan for developing the Non-Pipeline Alternatives program in Rhode Island.

The Company commits to developing the NPA Program parts over calendar years 2021 to 2023 and to providing an initial NPA Program, as detailed in Section 8.2, in the SRP 2023 Year-End Report filing. The Company commits to engaging with stakeholders to discuss and understand opportunities and challenges regarding NPAs throughout development of the NPA Program and its integral parts.

8.1 Definition of NPA

The Company proposes the following definition for NPAs.

NPA Definition:	Non-Pipeline Alternatives is the inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or "pipeline investment."
NPA Requirements:	These NPA investments are required to be cost-effective and are required to meet the specified gas pipeline need.

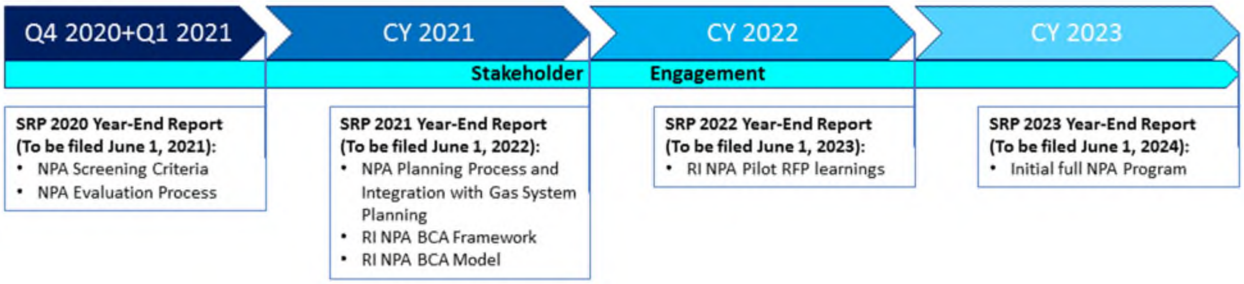
An NPA can include any action, strategy, program, or technology that meets this definition and these requirements. The Company is currently engaged in ongoing discussions with stakeholders about potential solution types in consideration of NPA solutions, proposals, and investment decisions.

Some technologies and methodologies that can be applicable as an NPA investment include demand-side measures, such as demand response, conservation or energy efficiency, and electrification, and supply-side measures, such as renewable natural gas (RNG). This is not intended to be an exhaustive list of possible demand-side and supply-side solutions. NPA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

8.2 NPA Program Development Plan

The Company proposes to develop the NPA program, process, and its integration with gas system planning over calendar years 2021 through 2023. Status and progress updates on NPA program development will be provided in the SRP Year-End Reports, as detailed in the figure below.

Figure 4. NPA Program Development Plan Timeline



<u>Stakeholder Engagement</u>

The Company intends to engage stakeholders continually throughout the development of the NPA program over the next three years via SRP TWG meetings. The Company intends stakeholders to be engaged during the development of specific program parts, as detailed in the figure above and the following program part descriptions.

The Company has been working to align the development of NPA frameworks across its Rhode Island, Massachusetts, and New York business units, which has resulted in modified development timelines in order to cross-jurisdictionally coordinate NPA programs. All three states are currently exploring NPAs and NPA framework, which allows for a standard framework for the market to follow, potentially increasing the opportunity to engage in NPA opportunities and deploy NPA solutions. The Company will present and solicit feedback in the SRP TWG meetings on the following major components of NPAs: eligible NPA technologies, NPA screening criteria, RFP structure and NPA bid process, and NPA BCA criteria, inputs and data sources.

<u>NPA Screening Criteria</u>

Given the limited experience with NPAs, screening criteria are currently in research and development. Generally, the NPA screening criteria will be designed to enable a large percentage of infrastructure projects to be eligible for consideration using NPAs. The Company's intent with the screening criteria in the NPA program will be to apply them to all pipeline needs that arise through planning analysis and system assessment. Such screening criteria will be integrated into gas system planning process as the NPA program is developed. These criteria will be developed as part of the SRP program and will be filed as an update in the SRP 2020 Year-End Report.

<u>NPA Planning Process and Integration with Gas System Planning</u>

Currently, the Company does not have a planning process defined for NPAs, which means it is not possible to identify projects where NPAs may be suitable or to put forth a solicitation to gather proposals. National Grid does have some prior methodology developed regarding targeted gas

DR[19], which the Company will fold into the development of the NPA program. Over the course of the SRP Three-Year Plan cycle, the Company will assess the existing NWA framework for applicability to NPAs, propose any modifications, and report on the process that will be used going forward. The Company will file a detailed NPA Planning Process in the SRP 2021 Year-End report.

Targeted Gas DR

Given that targeted gas DR is one potential technology and strategy that can be implemented as an NPA, the Company will develop targeted gas DR methodology as part of the NPA program and will do so in line with the overall NPA program development timeline.

NPA Evaluation Process

The Company plans to use an evaluation process analogous to the one that is deployed for NWAs but recognizes that there may be specific criteria that are applicable to NPAs and not NWAs. These differences will be identified during the course of the SRP Three-Year Plan cycle. As stated above, the proposed NPA evaluation process will be filed in the SRP 2020 Year-End Report.

RI NPA BCA Model

As described in Section 7.4 above, a full BCA analysis is required before any NWA investment is considered for proposal. To date, the Company does not have a BCA framework that is applicable to NPAs so one will need to be developed over the course of the SRP Three-Year Plan cycle. The BCA model for NPAs will be developed in alignment with Docket 4600. National Grid will complete a review of filings for NPA BCA frameworks and will compare them to the criteria outlined in Docket 4600 to ensure that any available NPA best practices are incorporated in the RI NPA program.

The Company will file an NPA BCA framework and a finalized RI NPA BCA Model in the SRP 2021 Year-End report.

Develop a Pilot for Learnings

The timeline described above means that the necessary components to identify, evaluate, and select NPAs will be filed by no later than the SRP 2021 Year-End report. Once the framework is established, the Company will develop an RFP and go to market for at least one eligible project so that the process can be tested and reviewed for efficacy and efficiency. If a proposal satisfies the Screening Criteria, Evaluation Process, is cost-effective, and is the least-cost option compared to the pipeline investment, then the Company will file the NPA proposal for approval with the PUC.

[19] "Aquidneck Island Long-Term Gas Capacity Study." *National Grid: Aquidneck Island Long-Term Gas Capacity Study*, National Grid, Sept. 2020, www.nationalgridus.com/media/pdfs/other/aquidneckislandlong-termgascapacitystudy.pdf.

Details from this RFP effort, including the proposals and their evaluation results, will be included in the SRP 2022 Year-End report.

At End of SRP Three-Year Plan Cycle

The Company commits to produce a detailed initial NPA Program at the end of the 2021-2023 SRP Three-Year Plan cycle. Note that, as with the Company's NWA Program, the NPA Program will continue to undergo program and process refinement and updates in the years following 2023 as the Company continues to learn and become experienced in NPA subject matter.

9. Rhode Island System Data Portal

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

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

The Portal provides this information to stakeholders, customers, and third-party solution providers. The main target audience is third-party solution providers and the main goal of the Portal is to provide information in order to engage the market for cost-effective grid solutions to reduce costs for Rhode Island customers. Therefore, the Portal is considered an SRP resource because it adheres to LCP standards and goals and is a complementary activity to meet electrical energy needs.

Costs related to Portal maintenance and routine operation of existing Portal aspects and work by FTEs are included in the current rate case. Only new enhancements to the Portal are covered in SRP Investment Proposals. New enhancements are expected to originate from collaborative consultation between National Grid and external stakeholders.

A public landing page for the Portal is located on the customer-facing National Grid website.[20]

9.1 Portal to Date

To date, the Portal includes tabs that detail select Company reports, a distribution assets overview map, a heat map, a hosting capacity map, sea level rise, and National Grid's NWA program. Each map tab has the date listed in its about dropdown for when the tab data was last updated.

The Company Reports tab lists documents such as the annual SRP reports, annual ISR proposals, the electric peak forecast, and redacted area study reports.

The FAQ tab lists common questions with standard responses to proactively inform and resolve confusion for visitors to the Portal, such as third-party solution providers.

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

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

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

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

The Sea Level Rise tab 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 National Grid electric distribution network in relation to areas that may experience potential coastal flooding impacts in the future. All sea level rise data is sourced and mirrored from the NOAA Sea Level Rise Viewer.[21]

The NWA tab that contains a link to National Grid's NWA Website[22], which contains information on the Company's NWA process and NWA RFP opportunities.

9.2 Portal Funding Plan

The Company estimates that no additional SRP funding will be required for currently planned Portal enhancements for calendar years 2021 through 2023.

[21] "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/.
[22] "Non-Wires Alternatives." *National Grid Business Partners*, National Grid USA, Inc., 13 Nov. 2019, www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/.

10. SRP Market Engagement

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

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

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

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

10.1 Market Engagement Channels

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

- Procurement and Contracting Platform: National Grid posts RFPs, receives vendor bids, and sends formal vendor communications in an official forum via its procurement and contracting digital platform for vendors. This is National Grid's Ariba platform.[23]

- Rhode Island System Data Portal: National Grid posts information regarding Company reports, feeder loading, hosting capacity, sea level rise, and links to National Grid's NWA Website.

- NWA Website: National Grid maintains a central public-facing website for its NWA program that details the Company's planning process, opportunities, and other NWA-related information.

- NWA Vendor Stakeholder Monthly Calls: National Grid directly interacts with vendor stakeholders in monthly calls to raise awareness on the NWA development and bid submission process and to inform vendor stakeholders on upcoming and current NWA

[23] "National Grid Ariba." *SAP Ariba*, Ariba Inc., 2020, http://nationalgrid.sourcing.ariba.com/.

opportunities. National Grid also hosts Q&A during these calls and receives feedback relevant to NWA.

- NWA Vendor One-on-One Meetings: National Grid directly interacts with vendor stakeholders on an individual basis as requested by vendor companies in order to learn about the vendor's background and technology and for the vendor to learn about National Grid's NWA program and purpose.

- NWA Email: National Grid maintains an email mailbox for NWA-specific inquiries and vendor engagement. National Grid also maintains an up-to-date mailing list for email outreach to the market, whether for engaging on the NWA Vendor Stakeholder Monthly Calls, announcing NWA RFP events, or communicating about the Portal.

- Utility Industry Events: Networking to continue to build National Grid's third-party relationships, socialize upcoming NWA opportunities, and promote National Grid's NWA forums.

- Cross-Functional Internal Coordination: The NWA team within National Grid coordinates cross-functionally with National Grid's CEM team on potential NWA options that involve targeted energy efficiency or targeted demand response.

These market engagement channels are utilized to enable qualifiable vendor engagement and to procure targeted bid proposals that solve the system need. These market engagement channels reduce market barriers by directly engaging with market vendors to clearly communicate upcoming NWA opportunities, clarify any points around National Grid's NWA process, and for National Grid to understand the market vendor demographic and the types of solutions they provide. The Company will also assess viable market engagement channels for NPA activities during development of the NPA program, whether such channels be similar, different, or the same as the NWA market engagement channels.

10.2 SRP Procurement

SRP procurement is a comprehensive process that encompasses, for the electric side, NWA planning and evaluation and will encompass the NPA program process currently in development. Procurement of SRP resources involve the following general process:

- Identification of a system need or opportunity
- Development of an RFP for the SRP opportunity
- Issue RFP to market on National Grid's Ariba platform
- Receive bid proposals
- Evaluation of submitted bid proposals
- Selection of bid proposal
- Filing of SRP proposal

The Company will utilize National Grid's existing strategic sourcing process for procurement of SRP and standard option investments. The existing strategic sourcing process is used for all procurements for goods, materials and services across National Grid US and National Grid UK. The process is designed to ensure thorough diligence and fairness and to establish clear histories of each procurement before award and contracting. The strategic sourcing process involves including all relevant stakeholders and internal approvals for the go-to-market strategy, bid review, detailed interviews and final selection of bidders. This process is in line with existing strategic procurement standards and has been refined for the specific purposes of procuring NWA solutions.

10.3 Market Engagement Proposal

The Company has currently entered a maintenance phase with market engagement for the Rhode Island System Data Portal. Therefore, the only planned SRP Market Engagement activities for the Portal are to maintain web traffic analytics to the Portal landing page. These web traffic analytics have no cost to operate or acquire.

The Company will continue to engage the market in the other channels in addition to the Portal, as detailed in Section 10.1. These other channels are already included in the work by FTEs and are therefore covered by the rate cases of all National Grid jurisdictions.

10.4 Market Engagement Funding Plan

The Company estimates that no additional SRP funding will be required for currently planned SRP Market Engagement for calendar years 2021 through 2023.

11. Coordination between SRP and other Programs

The Company recognizes that improved synchronization between SRP and Power Sector Transformation (PST), the Energy Efficiency Program Plan (EE Plan)[24], the Infrastructure, Safety and Reliability (ISR) Plans[25,26], the Renewable Energy Growth (REG) Program[27], the Grid Modernization Plan (GMP), and the Advanced Metering Functionality (AMF) Business Case is necessary and intends to maintain and improve coordination between these filings.

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

11.1 Coordination with Power Sector Transformation

This section describes how SRP coordinates with the Power Sector Transformation Phase One Report[28] goals and recommendations. Please refer to the PST Phase One Report for the full details on the goals and recommendations. Note that as programs and filings related to PST are approved, the Company will align SRP to maintain coordination. Correspondingly, as PST development progresses, SRP will progress in parallel.

The PST Phase One Report details the following goals:

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

[24] "Docket No. 4979 - 2020 Energy Efficiency Plan." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 15 Oct. 2019, www.ripuc.ri.gov/eventsactions/docket/4979page.html.

[25] "Docket No. 4995 - Electric Gas Infrastructure, Safety and Reliability (ISR) Plan for FY 2021." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Dec. 2019, www.ripuc.ri.gov/eventsactions/docket/4995page.html.

[26] "Docket No. 4996 - Gas Infrastructure, Safety and Reliability (ISR) Plan for FY 2021." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Dec. 2019, www.ripuc.ri.gov/eventsactions/docket/4996page.html.

[27] "Docket No. 4983." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Distributed Generation Board's (DG Board) and the Narragansett Electric Company d/b/a National Grid, 23 Oct. 2019, www.ripuc.ri.gov/eventsactions/docket/4983page.html.

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

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

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

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

3. **Build a flexible grid to integrate more clean energy generation.** The regulatory framework should promote the flexibility needed to incorporate more clean energy resources into the electric grid. These resources would help Rhode Island meet the greenhouse gas emission reduction goals specified in the Resilient Rhode Island Act of 2014 and consistent with Governor Raimondo's goal of 1,000 megawatts of clean energy, equal to roughly half of Rhode Island's peak demand, by 2020.

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

The PST Phase One Report also details the following recommendations:

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

SRP has synchronized with Distribution System Planning and the ISR filing to a certain extent, in that potential NWA opportunities are screened for as a standard part of DSP and that SRP takes into account the annual electric peak load forecasting, as seen in Section 7 and Appendix 1. The Company recognizes that improved synchronization between SRP and Distribution System Planning and the ISR filing is necessary. The Company is improving coordination between the SRP, ISR, and EE filings in internal calls, discussions, cross-department review requests, and other active coordination efforts. The Company has also improved stakeholder engagement and participates in enhanced discussions on SRP, NWA, and related policy and programs in the SRP TWG monthly meetings, which include the SRP TWG members, and NWA Quarterly meetings, which include the Division, OER, and National Grid. The work the Company has completed on the Portal to date and proposals for enhancement, which developed from stakeholder discussion and input, are described in Section 9.

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

This SRP Plan currently includes information on forecasted electric load growth, as seen in Appendix 1, for the main purpose of identifying and coordinating with potential NWA opportunities. This SRP Plan also includes the Rhode Island Electric Peak (MW) Forecast in Appendix 1 for additional, holistic information. The Company intends to implement robust stakeholder engagement and discussion on the electric forecasting process. Specifically, the Company hosted a meeting in November 2019 to review the electric forecasting process and engage and discuss the forecasting process with stakeholders. The Company will discuss the electric forecasting process with stakeholders on an annual basis. National Grid will host an annual stakeholder meeting at the beginning of each calendar year to review the electric forecast released in Q4 of the previous calendar year and to discuss the forecast and details for the next forecast release. Additionally, the Company filed its Gas Long-Range Resource and Requirements Plan on June 30, 2020 detailing the gas system forecast period from 2020/21 to 2024/25.[29]

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

SRP establishes customer and third-party data access through the Rhode Island System Data Portal. The 2019 SRP Report proposed further work on the Portal to improve data access for external parties. The 2019 SRP Report also proposed commitment to discussion on posting NWA RFPs and to inclusion of redacted area studies in the Portal. The Company further improved data access by setting up an NWA Website in order to post information and RFPs on the Company's NWA process and opportunities. SRP does not currently maintain a specific data access plan, as a document or otherwise. The Company will commit to maintaining alignment between SRP and AMF with regard to the AMF Data Governance and Management Plan and will participate in future collaborative discussions about data access and security.

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

The 2019 SRP Report presented the Company's research and findings on locational incentive analysis for Rhode Island. From further deep cross-functional research and through engagement and discussion with stakeholders, the Company presents its findings on locational value for the SRP program as follows:

> Any incentive, as a benefit or paid incentive, for SRP investments are inherently locational due to the targeted nature of NWA or NPA projects and the programs that support these projects. The incentive categories that apply to SRP investments include those for

[29] "Gas Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 30 Jun. 2020, http://www.ripuc.ri.gov/eventsactions/docket/5043-NGrid-LRGas%20Plan-2020-21%20to%202024-25%20(6-30-20).pdf.

Customers, for Third-Parties, and for National Grid, as detailed below in Table 8. Incentives for customers are interpreted as the benefits derived from implementing SRP investments such as NWA or NPA projects. The incentive to the Company, the SRP Savings-Based Incentive, is filed separately for recovery and does not count against a specific project's cost-effectiveness.

Table 8. SRP Incentive Categories

Group	Corresponding Incentive	Exists/Applied Currently?
Customers	Benefits of SRP Investment (NWA, NPA)	Yes
Third-Parties	No current incentive	No
National Grid	SRP Savings-Based Incentive	Yes

National Grid has determined that any Company-sponsored paid incentive, such as ones for third-parties or for customers' paid participation, must be counted as a cost in the BCA of any project as such incentives would be deemed part of project or program implementation. Paid participation incentives for customers, such as those for NWA or NPA projects comprised of targeted EE or targeted DR in addition to existing statewide EE or DR programs, are factored as a component of project costs; these paid incentives are typically the major component of the cost for such project types.

There is currently no incentive structure for direct, paid incentives to third-parties in the SRP program. The NWA Deferral Value is interpreted as an indirect incentive for third-parties. Any paid incentive for third-parties that is Company-sponsored would have to count as a cost in the BCA. Therefore, to be an effective incentive and maintain cost-effectiveness for any SRP project, third-party incentives would have to be sourced from outside the Company.

For locational incentives or value more specific than the locational value based on targeted substations or feeders in an NWA project, SRP would require the granular datapoints and datasets provided by advanced metering, such as those detailed by the AMF proposal.

11.2 Coordination with Energy Efficiency

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

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

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

As energy efficiency is a least-cost resource, the Company will continue to identify opportunities where it can target energy efficiency to create multifaceted benefits for customers. For example, the Company can utilize the increased visibility from the Rhode Island System Data Portal to target energy efficiency and demand response in areas that would benefit from load reduction. Other examples may include enhanced or targeted community initiatives or enhanced marketing for ConnectedSolutions, the Company's demand response program, with specific system needs. Such enhanced marketing would be targeted to customers based on the system need, whether it is targeted to customers supplied by a feeder, set of feeders, a whole substation, or a geographical area.

Additionally, SRP will coordinate with EEP on preemptive targeted EE/DR to address specific feeders and/or substations that are highly loaded or forecasted to be overloaded in future years. This preemptive targeted EE/DR would take place before a system need arises in order to optimally avoid grid investment. Coordination will entail tailored marketing outreach efforts to customers to inform them of the local need and in order to not conflict or confuse with existing EE/DR marketing.

The Company also maintains synchronization and clear communications between the SRP TWG and the EE TWG: The National Grid program leads for the EE Plan and for SRP attend each other's TWG meetings and coordinate via email.

The Company will report on the evaluation results of internally-sourced targeted EE or targeted DR bid proposals for an NWA opportunity in the annual SRP Year-End Reports, as applicable.

11.3 Coordination with Infrastructure, Safety and Reliability

The Company prepares area studies to identify reliability and safety needs and associated solution options and recommendations for the Electric Distribution business in Rhode Island. The solutions identified in area studies can include both wires and non-wires alternatives. After an analysis of all wires and non-wires options identified, the Company recommends the solution that is the least-cost option that will meet the needs identified in the area studies. If the recommended solution is a non-wires alternative, progression of the bidding, approval and implementation processes will progress through the SRP program. If the recommended solution is a wires alternative, it may be progressed through the Electric ISR Plan at some point in the future. Coordination occurs between the distribution planners and the NWA team by the planners communicating to the NWA team the screened system needs that have potential for an NWA option and by the NWA team communicating to the distribution planners any viable NWA options that passed evaluation.

Please see Section 7 for further detail regarding the planning process and coordination.

The Company will report on the wires and pipes investment screening results for potential NWA or NPA opportunities in the annual SRP Year-End Reports. The Company is inherently coordinated between the SRP Plan and Electric ISR Plan as part of the normal course of business with regard to planning and development of NWA and NPA opportunities in parallel consideration to wires and pipes solution investments.

11.4 Coordination with Grid Modernization and AMF

The SRP team is tracking the development and implementation of the Grid Modernization Plan and Advanced Metering Functionality Business Case filings to ensure future coordination is maintained with the outcome of these plans.

The Company will coordinate SRP with the GMP and the AMF filings once they are approved to ensure cohesive and comprehensive plan framework and implementation. To ensure that efforts, projects, and programs are not being duplicated between SRP and GMP, namely with respect to the Portal, the Company will recover new support costs to manage the development of future grid modernization compliance data and reports through the Company's future rate case filings while new enhancements to the Portal will be proposed through SRP. The Company has determined that there is no duplication of work between projects in SRP and AMF since the context of the two filings are wholly different: AMF handles smart meters and their data governance while SRP handles new enhancements to the Portal, SRP-related market engagement and outreach, and NWA and NPA project proposals. Note that components of the AMF program, namely the data output, can support SRP programs; however, the AMF filing investments themselves, namely the smart meter infrastructure, is not duplicative with SRP investments.

The AMF Data Governance and Management Plan is intended to be integrated, consolidated, and cross-functional. From this, data governance for SRP is intended to be covered by the AMF Data Governance and Management Plan. SRP will maintain alignment with AMF to ensure SRP's relevant data concerns are included in the AMF Data Governance and Management Plan, namely with regard to data access on the Portal.

The SRP team is aware that the AMF proposal includes data availability and access. Such data can further improve planning and development of potential NWA opportunities, both on the internal distribution planning side and on the external side by furnishing more granular, anonymized load data to third-party bidders. Additionally, the SRP team understands that third-party data access to AMF may be required for the implementation of certain NWA projects. For example, the addition of smart meter data realized from the AMF investment can provide planners with more granular data and thusly provide the ability to aide in forecasting and strategic planning. Furthermore, National Grid control center operators may have more informed datapoints from assets on the system and therefore have further clarified control, such as with front-of-the-meter (FTM) battery storage assets. The SRP and NWA teams will plan for how the NWA development process may improve with respect to the availability and granularity of data following implementation of the AMF proposal. The SRP and NWA teams are therefore coordinating with the development and implementation of the AMF filing with these specific data access themes in mind, in addition to following the AMF Business Case in general.

The SRP team is aware that Grid Modernization discusses functional topics such as EV, DG, energy storage, demand response, and other technologies and methodologies through its development and implementation. The SRP and NWA teams are therefore synchronized with the development and implementation of the GMP to ensure coordination is maintained. The Company has internal, regular check-in meetings and additional one-on-one meetings to stay synchronized and coordinated across Company programs and filings, such as between SRP, GMP, and AMF. The Company will report on program updates relevant to SRP in coordination with GMP and AMF in the annual SRP Year-End Reports, as applicable. The Company maintains overall coordination between SRP and the GMP and AMF filings.

12. SRP Timeline

Sections 4.6, 5.5, and 4.4.B of the Standards, respectively, outline the following timeline for the development of the program implementation plans and detailed budgets. National Grid will work with the EERMC and the SRP TWG to meet these deadlines:

1. SRP Three-Year Plans
   a. By October 21, 2020 and triennially thereafter: The EERMC will vote whether to endorse the System Reliability Procurement Plan.
   b. November 21, 2020 and triennially thereafter: Submit the System Reliability Procurement Plan for three years of implementation beginning January 1 of the following year.

2. SRP Investment Proposals
   a. The Company will file SRP Investment Proposals as needed, and will aim to file SRP Investment Proposals alongside, and separately from, annual ISR Plans when possible.
   b. The Company requests the PUC rule on SRP Investment Proposals within 60 days of filing.
   c. SRP Investment Proposals will contain content, proposals, and funding requests for, but not limited to, the following:
      i. NWA projects
      ii. NPA projects
      iii. New enhancements for the Rhode Island System Data Portal
      iv. Outreach and Engagement Plans for SRP Market Engagement

3. SRP Year-End Reports
   a. National Grid will submit a Year-End Report to the EERMC and the SRP TWG for their review and comment annually at least three weeks before the EERMC's scheduled meeting prior to the filing date that year.
   b. The EERMC shall vote whether to endorse the Annual Plan prior to the prescribed filing date, annually.
   c. June 1, 2021 and annually thereafter: Submit the Year-End Report detailing plan implementation for the preceding calendar year.
   d. The SRP Year-End Reports will contain content including, but not limited to:
      i. Screening results summary on all applicable wires and pipes investments for potential NWA or NPA opportunities.
      ii. Details on Rhode Island Company electric service projected load growth rates.
      iii. Status and progress updates on potential NWA or NPA opportunities.
      iv. Status and progress updates on active and implemented NWA or NPA projects.

v. Status and progress updates on new enhancements for the Rhode Island System Data Portal, as applicable.
vi. Status and progress updates on SRP market engagement efforts, as applicable.
vii. Proposals to update the Company's NWA screening criteria for Rhode Island, as applicable.
viii. Proposals to update the Company's RI NWA BCA Model, as applicable.

The Company proposes the annual reporting plan for SRP Year-End Reports as detailed above for calendar years 2021 through 2023.

13. Miscellaneous Provisions

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

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

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

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

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY
D/B/A NATIONAL GRID

11-13-2020

By its Attorney, Date
Andrew S. Marcaccio

ACADIA CENTER

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Appendices

Appendix 1

Appendix 1 – Rhode Island Company Electric Service Projected Load Growth

Forecasted Load Growth for NWA Opportunities

This appendix provides an overview and update on the Rhode Island electric service projected load growth rates as well as the forecasted load growth for locations in Rhode Island that have the potential for NWA opportunities.

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

The forecasted load growth rates for cities and towns in Rhode Island are shown in the Rhode Island Projected Load Growth Rates table below. Additionally, as seen in the sections below for Bristol, Kent, Newport, and Providence counties, the average annual growth rates are projected to be negative over the next 10 years.

The Bristol 51 NWA opportunity intends to address the forecasted load growth and system need in Bristol County. The Bonnet 42F1 and South Kingstown NWA opportunities intend to address the forecasted load growth and system need in Washington County.

The Company has not presently identified other NWA opportunities through the distribution system planning process, which is detailed in Section 7.

The Company accounts for DG, DR, EE, EV, and PV impacts in the Company's electric peak load forecasting.

Forecasted Load Growth in Bristol County

The Bristol County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.8% for the next 10 years. This rate is less than the statewide average annual growth rate of -0.6%.

Forecasted Load Growth in Kent County

The Kent County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.7% for the next 10 years. This rate is less than the statewide average annual growth rate of -0.6%.

Forecasted Load Growth in Newport County

The Newport County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.7% for the next 10 years. This rate is less than the statewide average annual growth rate of -0.6%.

Forecasted Load Growth in Providence County

The Providence County area annual weather-adjusted summer peak is expected to decrease at an average annual growth rate of -0.9% for the next 10 years. This rate is less than the statewide average annual growth rate of -0.6%.

Forecasted Load Growth in Washington County

The Washington County area annual weather-adjusted summer peak is expected to be flat at an average annual growth rate of 0.0% for the next 10 years. This rate is greater than the statewide average annual growth rate of -0.6%.

Rhode Island Projected Load Growth Rates

State	County	Town	Annual Growth Rates (%) 2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	5-year Average (%) 2020 to 2024	10-year Average (%) 2020 to 2029
RI			-0.9	-1.2	-0.4	-0.5	-0.5	0.1	-0.6	-0.7	-0.7	-0.8	-0.7	-0.6
	BRISTOL		-1.1	-1.4	-0.6	-0.7	-0.7	0.0	-0.7	-0.8	-0.8	-0.9	-0.9	-0.8
	KENT		-1.1	-1.4	-0.6	-0.7	-0.6	0.0	-0.7	-0.8	-0.8	-0.8	-0.9	-0.7
	NEWPORT		-0.9	-1.3	-0.5	-0.6	-0.6	0.1	-0.6	-0.7	-0.8	-0.8	-0.8	-0.7
	PROVIDENCE		-1.4	-1.7	-0.8	-0.9	-0.8	-0.2	-0.8	-0.9	-0.9	-0.9	-1.1	-0.9
	WASHINGTON		0.0	-0.4	0.3	0.2	0.1	0.7	-0.1	-0.2	-0.3	-0.4	0.0	0.0
	WASHINGTON	Kenyon	-3.4	-3.5	-2.5	-2.4	-2.2	-1.4	-1.9	-1.9	-1.9	-1.8	-2.8	-2.3
	WASHINGTON	Narragansett	-0.3	-0.7	0.0	-0.1	-0.2	0.4	-0.3	-0.4	-0.5	-0.6	-0.3	-0.3
	WASHINGTON	Peace Dale	0.5	0.0	0.7	0.5	0.4	0.9	0.2	0.0	-0.2	-0.2	0.4	0.3

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 5080
2021-2023 System Reliability Procurement Three-Year PlanReport
Appendix 1

NARRAGANSETT ELECTRIC COMPANY

2020 Electric Peak (MW) Forecast

15-Year Long-Term

2020 to 2034

November 2019

Original, 11/01/2019

Economics and Load Forecasting
Advanced Data & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/01/2019	- ORIGINAL

General Notes:

- Hourly load data through August 2019; projections from 2020 forward;
- Economic data is from Moody's vintage August 2019.
- Energy Efficiency data is internal data vintage August 2019.
- Distributed Generation data is internal data vintage August 2019.
- Electric Vehicle data is POLK data vintage August 2019.
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (1/2003 to 6/2019), internal unreconciled **preliminary** data (Jul 2019 to Aug. 2019).
- Peak load data is metered zonal load; but without ISO bulk system losses.
- The term "Weather-Normal" is based on a twenty-year average.
- PV impacts are based on non-supply (ISO) installations
- High and low DER scenarios are added this year in addition to the standard base case
- Demand Response added this year
- The impacts of changing peak hours over time due to DERs is considered

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CONTENTS

Summary

National Grid's US electric system is comprised of four companies serving 3.5 million customers in Rhode Island, Massachusetts, and upstate New York. The four electric companies are: Narragansett Electric Company, serving 0.5 million customers Rhode Island, Massachusetts Electric Company and Nantucket Electric Company, serving 1.3 million customers in Massachusetts and Niagara Mohawk Power Company serving 1.7 million customers in upstate New York. Figure 1[1] shows the Company's service territory in the U.S.

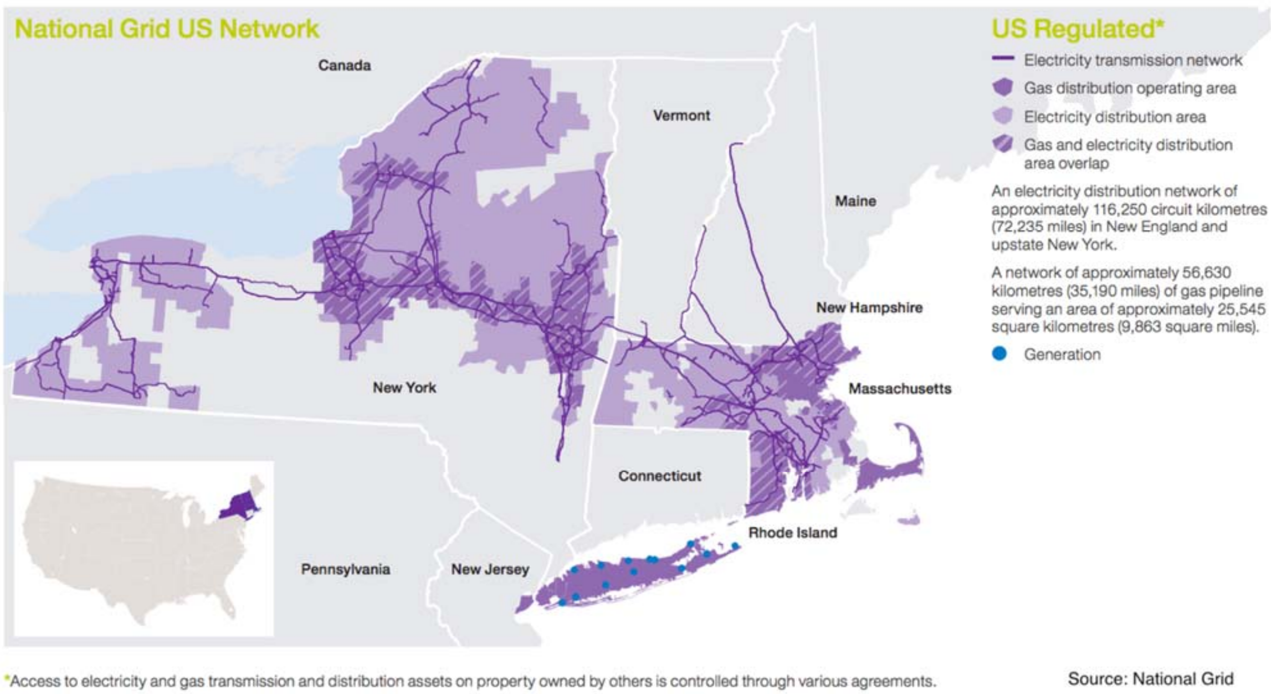

Figure 1: National Grid U.S. Service Territory

Forecasting peak electric load is necessary for the Company's capital planning process so the Company can assess the reliability of its electrical infrastructure, procure and build required facilities in a timely manner, and provide system planning with information to prioritize and focus their efforts.

The Company's[2] peak demand in 2019 was 1,750 MW on Sunday, July 21st at hour-ending 18. This 2019 peak was 12% below the company's all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

This summer's weather for the Company peak was considered warmer than 'normal' (or average). The peak weather fell in the 82 percentile of peak weather over the last 20 years. This means that only 18%

[1] National Grid also serves gas customers in these same states which are also shown on this map.
[2] Company refers to Narragansett Electric Company for the remainder of this report.

of summers are expected to be warmer[3]. This year's peak is considered 3 MW below the peak the company would have experienced under normal weather and 'day of the week' conditions (Sunday peaks are very unusual). Thus, on an adjusted "normal" basis this year's peak was estimated to be 1,753 MW, a decrease of 1.8% compared to last year's adjusted peak.

The forecast indicates that the service territory will experience a peak decline of about 0.6% annually over the next fifteen years, primarily due to the impacts of distributed energy resources (DERs) offsetting any underlying economic growth.

Figure 2 shows this forecast graphically.

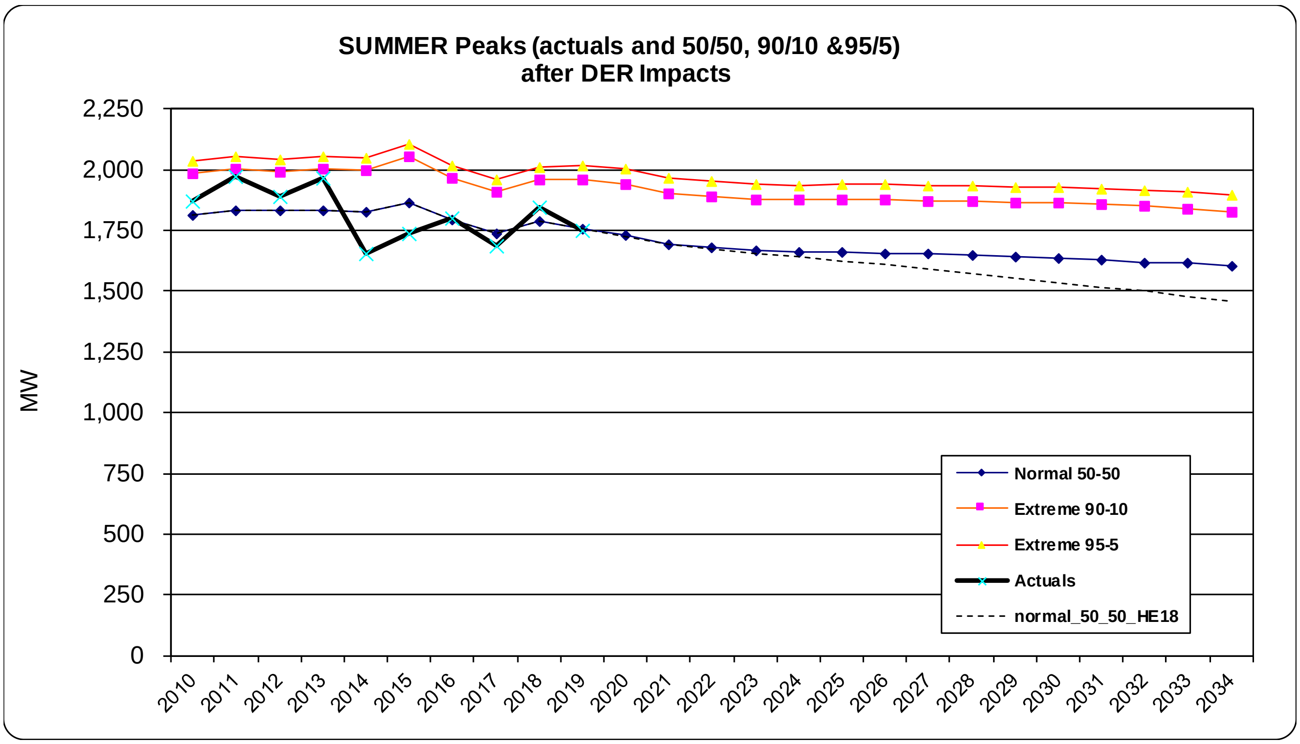

Figure 2: Historical (actual & weather-adjusted) and Projected Summer Peaks

This forecast incorporates the impacts of a changing hour of the peak over time. In general, due to increased solar photovoltaics (PV) and electric vehicles (EV) the hour of the peak moves from its current late afternoon/early evening time to later in the evening and early night time by the end of the fifteen-year planning horizon. As this occurs, the impact of PV is less pronounced on the new peak hour. For comparison, the dotted line in Figure 2 shows how the load at the 5-6 PM hour, where PV has more impact continues to decline over the planning horizon.

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

Forecast Methodology

The overall approach to the peak forecast is to relate (or regress) peak MWs to aggregate system energy and economic indicators (if appropriate).

The model is developed based on a "reconstructed" model of past load. That is, claimed energy efficiency, installed solar PV and demand response impacts are added back to the historical data set before the models are run. Electric vehicle impacts are removed from the historical data set. The statistical forecast is made based on the "reconstructed" data set. Then, the future cumulative estimates of savings or additions for these DERs are taken out or added to the statistical forecast to arrive at the final forecast. Hourly profiles for the DERs are applied to the hourly profiles for the loads to determine the annual peaks.

The results of this forecast are used as input into various system planning studies. The forecast is presented for three weather scenarios. The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes. For distribution planning, the degree of diversity is reduced and the variability of load is greater, so a 95/5 forecast is used. The 50/50, or weather-normal scenario is used for capacity market, strategic scenarios, incentive mechanisms and other relevant work.

Weather Assumptions

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

The weather variables used in the model include heating degree days for the winter months and a temperature-humidity index (THI)[4] for the summer months. Other variables such as maximum or minimum temperature on the peak day are also evaluated. These weather variables are from the actual days that each peak occurred in each season over the historical period. Summer THI uses a weighted three-day index (WTHI)[5] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for a normal (50/50) weather scenario and extreme weather scenarios (90/10 and 95/5)[6].

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

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

Figure 3 shows the historical, weather-normal, and weather-extreme values for WTHI for the Company.

[4] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.
[5] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.
[6] Normal distribution is assumed to derive the extreme weather scenarios. This "probabilistic" approach employs "Z-values" and standard deviations to calculate the extreme weather scenarios. As a result, the more spread out the numbers on peak days over the historical period, the more the 90/10 and 95/5 values will be above the mean (or the normal).

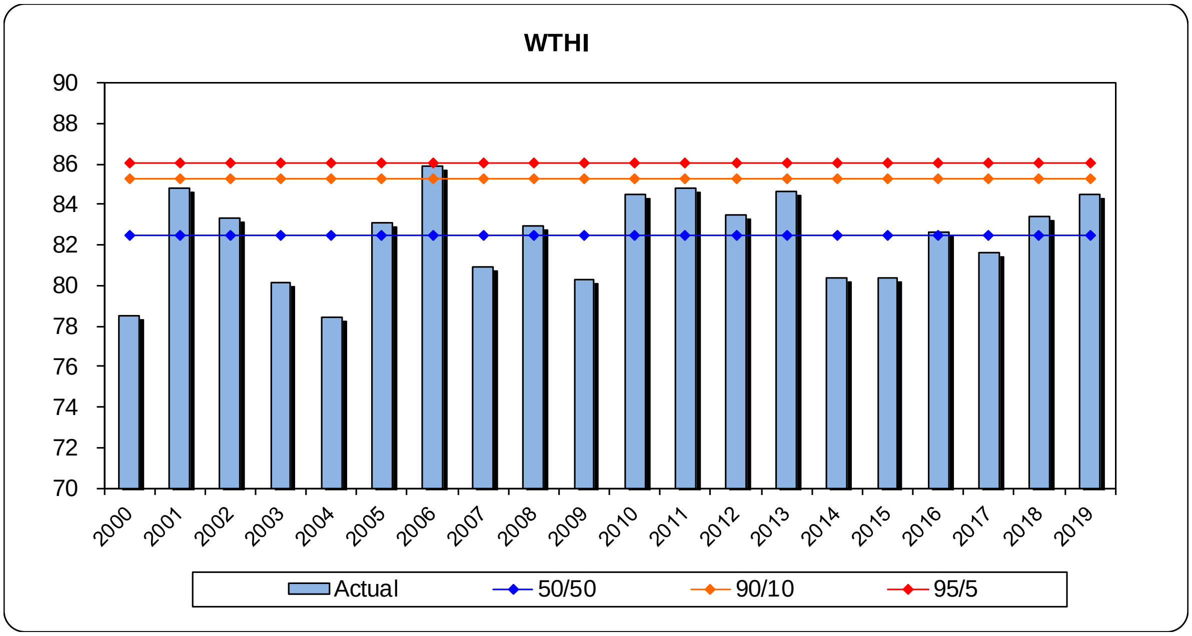


Figure 3: Actual, weather-normal and extreme WTHI

Distributed Energy Resources (DERs)

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

A base case forecast is developed for each of the DERs and is part of the official forecast. For each of the DERs, a higher case and a lower case are developed, if appropriate. The inclusion of multiple scenarios for each DER, as well as the different combinations of them, provides system and strategic planners with additional information to make informed decisions. The discussion below is based on the expected, or base case.

Figure 4 shows the expected loads and impacts for the DERs each year. In general, DERs are expected to decrease future growth from 0.4% per year over the next fifteen years to <u>negative</u> 0.6% per year.

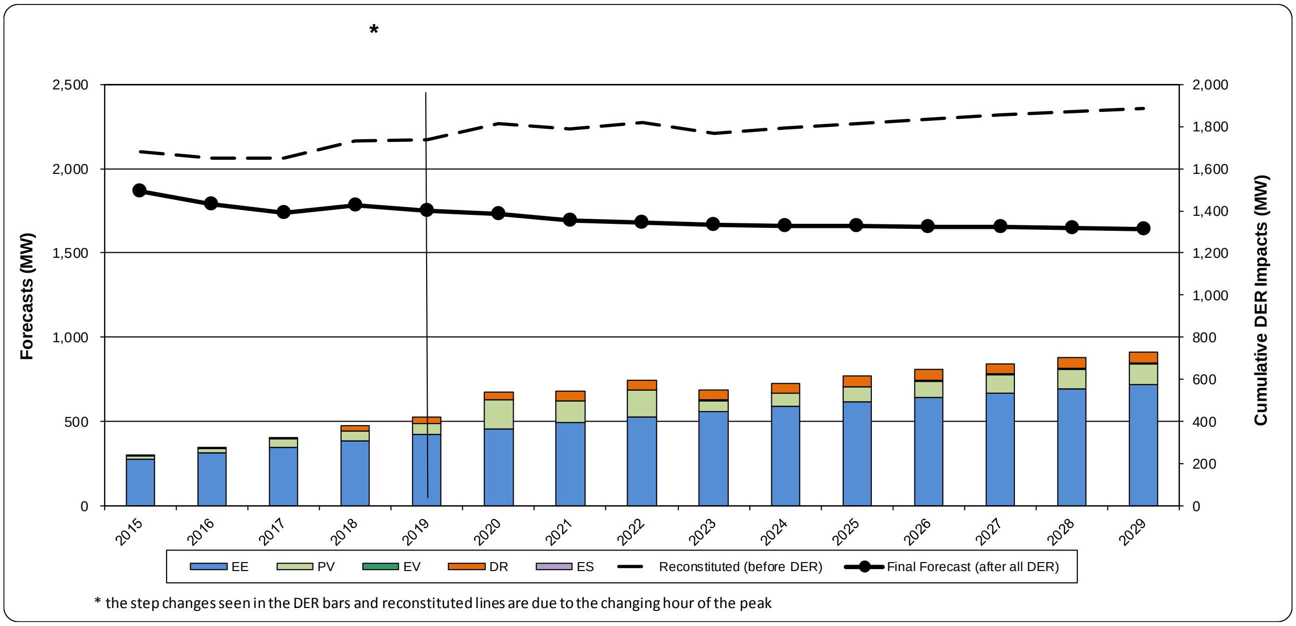


Figure 4: Annual impact of DERs

In addition to impacting the magnitude of the peak, the DERs change the peak-day load shape which shifts the peak hour over time. Over time, the peak hours shifts to later in the day. The impacts of each DER on the peak hour change as the peak hour shifts[7]. In general, due to increased solar photovoltaics (PV) and electric vehicles (EV) the hour of the peak moves from its current time of 5-6 PM to 7-8-9 PM over the fifteen-year planning horizon. As this occurs, the impact of PV is less pronounced on the peak hour. The visible decrease in DERs shown in Figure 4 in 2023 is due to this shift.

Each of the DERs is discussed next.

---

[7] While the figure shows a step function drop in DERs as the hour shifts, in practice each DER would have a smoother impact. This table only shows each 'hour-ending' value.

Energy Efficiency (EE)

National Grid has run energy efficiency programs in its Rhode Island jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term, energy efficiency targets are based on approved company programs. Over the longer term, the Company assumes the market begins to saturate and the rate of new EE is assumed to decline. This allows continued cumulative growth of EE over time, however at a lower rate of new EE each year to account for long-term saturation, higher marginal costs, and a lower load base to capture savings from as long-term EE lowers overall load over time. (This practice of declining EE over time is similar to what each regional ISO does).

Figure 4 above shows the expected load and energy efficiency program impacts to peaks by year for the base case. As of 2019, it is estimated that these EE programs have reduced load by 338 MW, or 15.6% compared to the counterfactual with no EE programs. By 2034, it is expected that this reduction will grow to 654 MW or 28.4% of what load would have been had these programs not been implemented. Over the fifteen-year planning horizon these reductions lower annual peak growth from 0.4% to negative 0.1% per year.

Solar - PV[8]

There has been a rapid increase in the adoption of solar PV throughout the state. Actual installed PV is tracked by the Company and used for the historical values in Figure 5. The projection for the future is based on an estimate of installations for units already in the application queue for the first two years, then a continuation of those levels until year 2023, and then a slowly declining number of new annual installations to account for saturation.

Figure 5 shows the historical and projected connected PV installations. As of 2019, it is estimated about 224 MWs will have been connected, growing to 1,506 MW by the end of the planning period.

[8] This discussion is limited to PV which expected to reduce loads and would not include those PV installations considered as ‘supply’ by the ISO. This can include both ‘behind-the-meter” and in “front-of-the-meter” for those installations like community solar which is allocated back to customers.

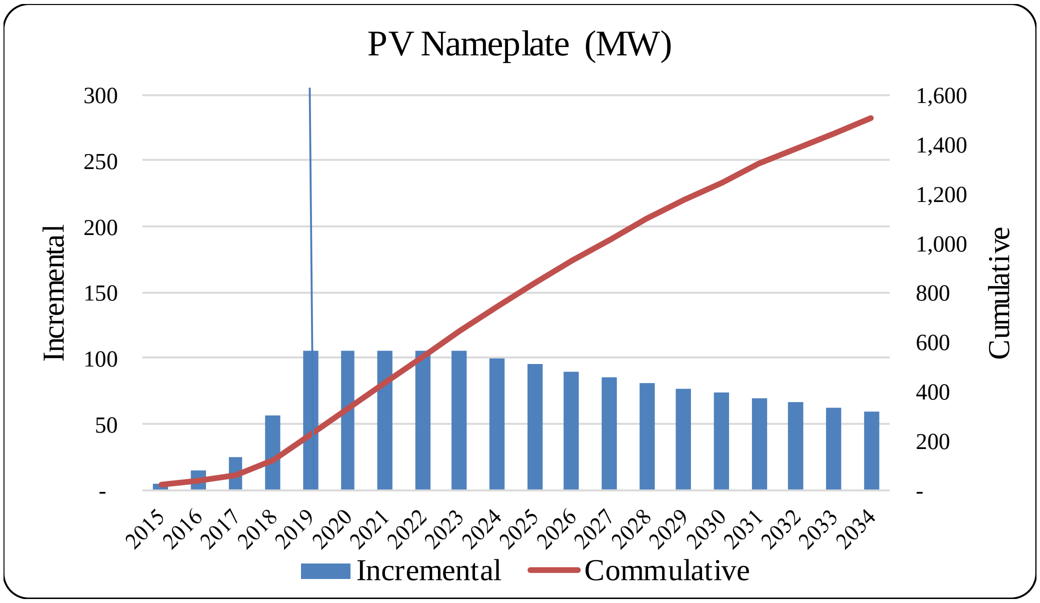


Figure 5: Solar-PV connected nameplate (AC) MW by year

While installed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less daylight.

Electric Vehicles (EV)

Electric vehicles increase peak load over time. Electric vehicles of interest are those that "plug-in" to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that could have potential impacts on the electric network.

The Company has been tracking EV adoption in its service territory for several years. Each year, the rate of electric vehicle adoption has been increasing. The base case forecast for the number of newly registered electric vehicles within the Company's service territory uses the recent trend showing this increased rate of adoption yielding an increasing number of new EVs each year.

Figure 6 shows the historical and estimated number of EVs in the Company's upstate New York service territory. As of the end of 2019, it is estimated that almost 2,000 EVs will be on the roads in the service territory, growing to almost 34,000 by the end of the fifteen-year planning horizon.

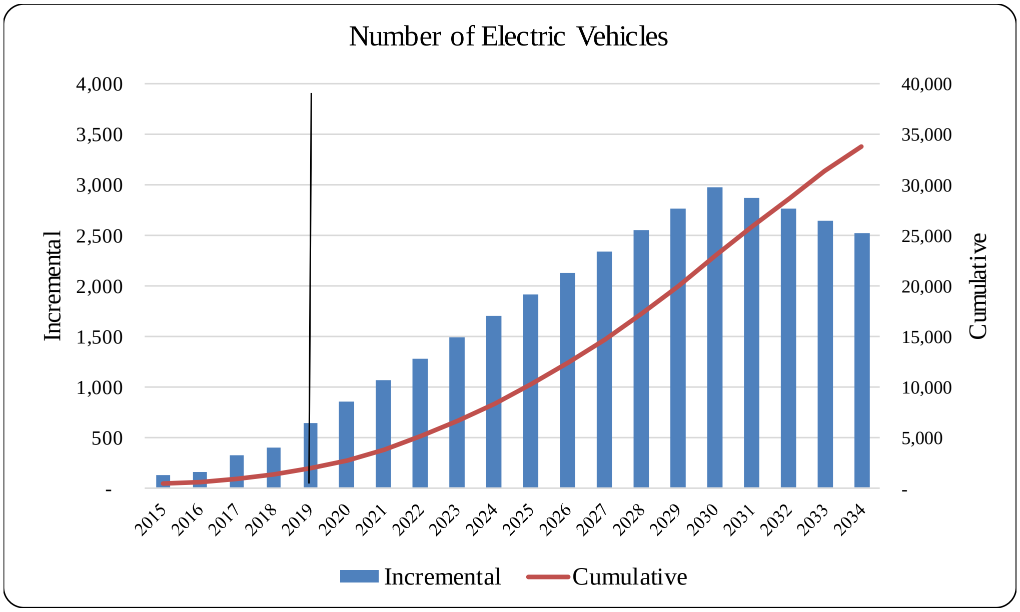


Figure 6: Number of Incremental and Cumulative EVs

It is estimated that these vehicles may have increased cumulative summer peak loads by about 0.4 MW as of 2019, increasing to about 13 MW of cumulative peak load increase in year 2034. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[9] electrification.

<u>Demand Response (DR)</u>

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

In general, there are two categories of Demand Response programs in Rhode Island. These are ISO programs and Company retail level programs.

The ISO programs, referred here as "wholesale DR", have been active for several years and were activated multiple times over that period. There were no ISO activations this year. The company's policy has been to add-back reductions from these dispatches to its reported system peak numbers. This is because the Company cannot dispatch the ISO resources so there is no guarantee that these ISO DR events would be at the times of Company peaks. Therefore, the company must plan assuming they are not called.

[9] Beneficial electrification is based on an overall portfolio of lowered carbon emissions from the transportation sector coupled with lower/carbon free generation of electricity in the power sector to support the charging of the EVs.

The Company recently began to run its own DR program at the 'retail', or customer level over the last few years. In contrast to the wholesale level DR programs implemented by the ISO, these programs are activated by the Company.

In 2019, estimated impact of the retail DR program was about 27 MW and is expected to grow to about 54 MW, or 2.3% of summer peak load by year 2034. The Company DR program was not called on this year's Sunday, July 21st peak. The hours of dispatch for DR would be assumed to move over time to capture the hours of the peak, however, as the hours of the peak move outside of normal commercial sector activity it is expected that additional DR impacts would be harder to achieve.

All prior discussion on load & DERs above is limited to the base case. Additional higher and lower scenarios are provided later in this section (see 'DER scenarios') and in the Appendices.

Peak Day 24 Hourly Curves

While the single summer peak values discussed above are of major importance, the estimated impacts due to DERs on the load profile on these peak days is also important. A 24-hour peak day load profile is provided below. This allows the Company to look beyond the traditional approach of predicting only the 'single' highest seasonal system peak each year. The process looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as more DERs are added. For example, as more and more solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. And as more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figure 7 shows the impact of the "24 hour" peak summer day for selected years over the planning horizon for the base case DERs.

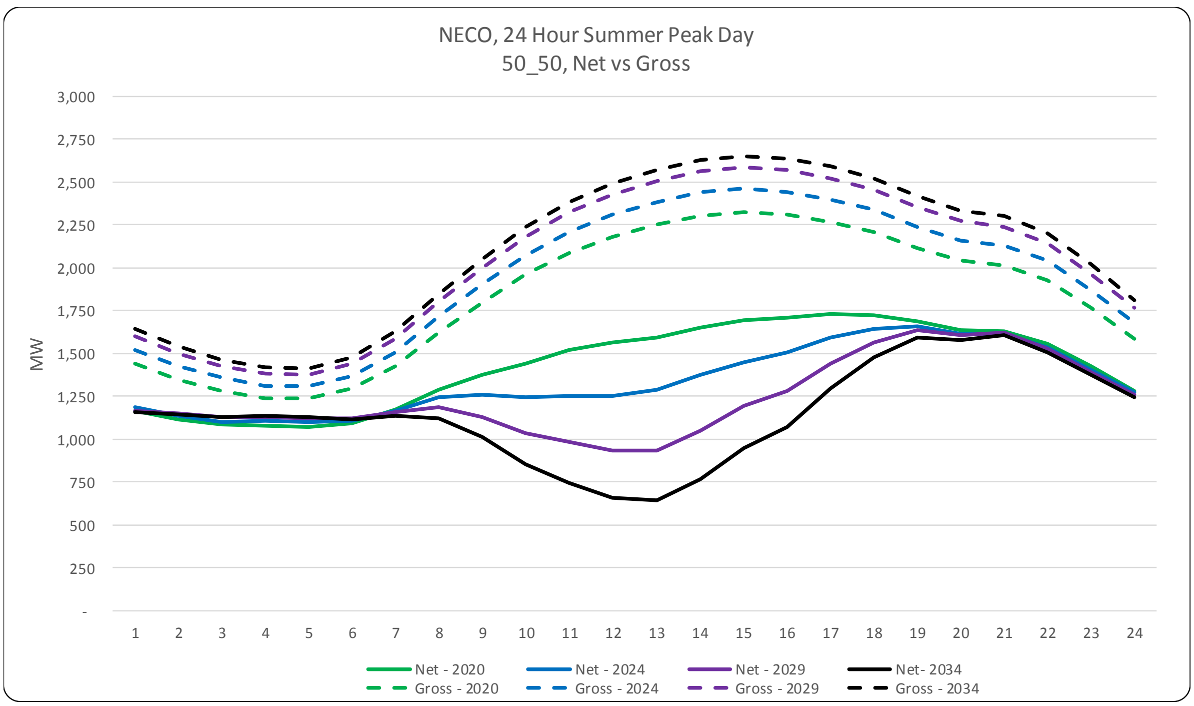


Figure 7: Peak Summer day hourly load, pre and post DERs

Figure 7 clearly shows how the expected DERs not only lower the loads, but also shift the hour of the peaks. "Gross" refers to loads before DER impacts and "Net' refers to loads after DER. The selected years are 2020, 2024, 2029 and 2034.

Figure 8 shows the impact of the "24 hour" peak winter day for selected years over the planning horizon with the base case DERs.

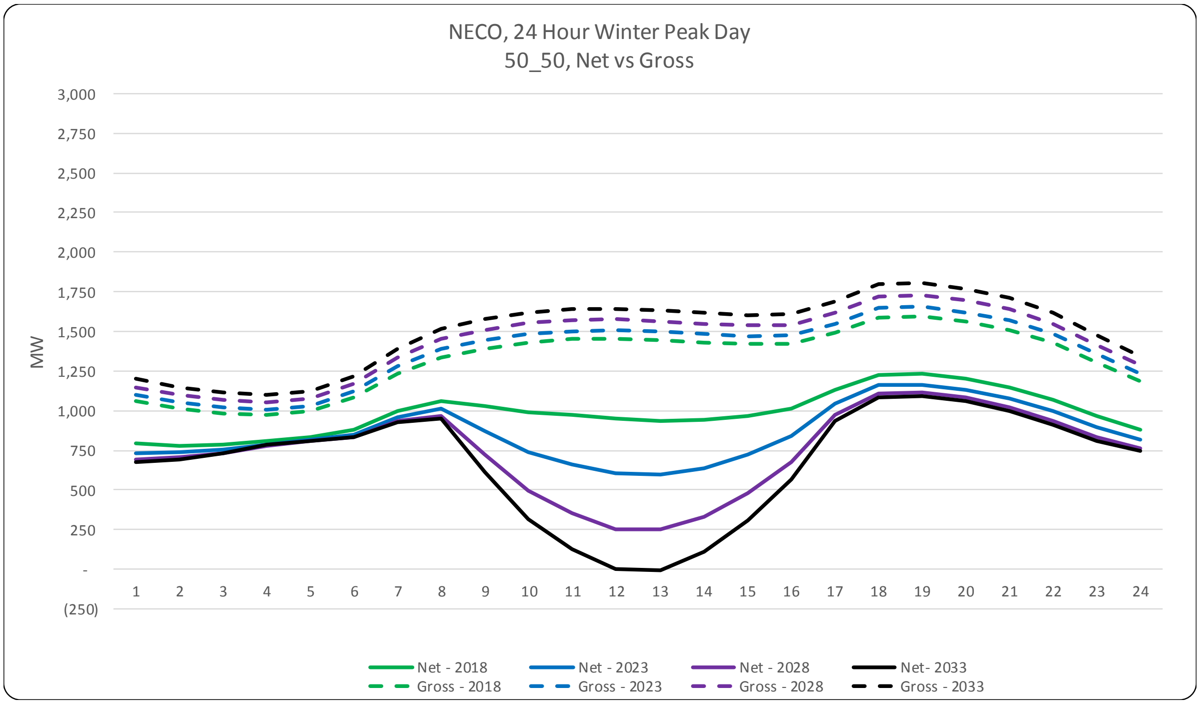


Figure 8: Peak Winter day hourly load, pre and post DERs

This figure shows the dual peaks associated with winter days as well as the very low load hours during the daytime hours due to solar and the rapid ramp ups needed as the sun sets. The figures above show the Gross and Net load profiles for the base case DERs.

Appendix C contains additional load shapes for other day types including: summer, winter and shoulder month average weekdays and weekends. These show the varying seasonal patterns as well as the lower load shoulder months which are mostly comprised of base load with minimal impacts of cooling or heating. Weekend load patterns also provide insight to lower load profiles since there is no weekday business load. One item of note is that where the highest peaks tend to drop over time for the system summer peaks, in the average day profiles one can see some growth in the evening and early night time hours. One reason for this is that demand response is not considered to be implemented in shoulder periods and on average days.

DER Scenarios

The body of this report thus far has shown results for the peak forecast with the base case DERs scenario. The Company has also looked at a number of scenarios where each of the DERs (EE, PV, EV and DR) also has a higher case and a lower case scenario, as appropriate. Looking at a range of scenarios can provide planners with additional information on what loads might be under various combinations of DER scenarios[10].

Figure 9 shows what the range of annual summer peaks could look like for all of the various combinations of DER scenarios for each of the next fifteen years.

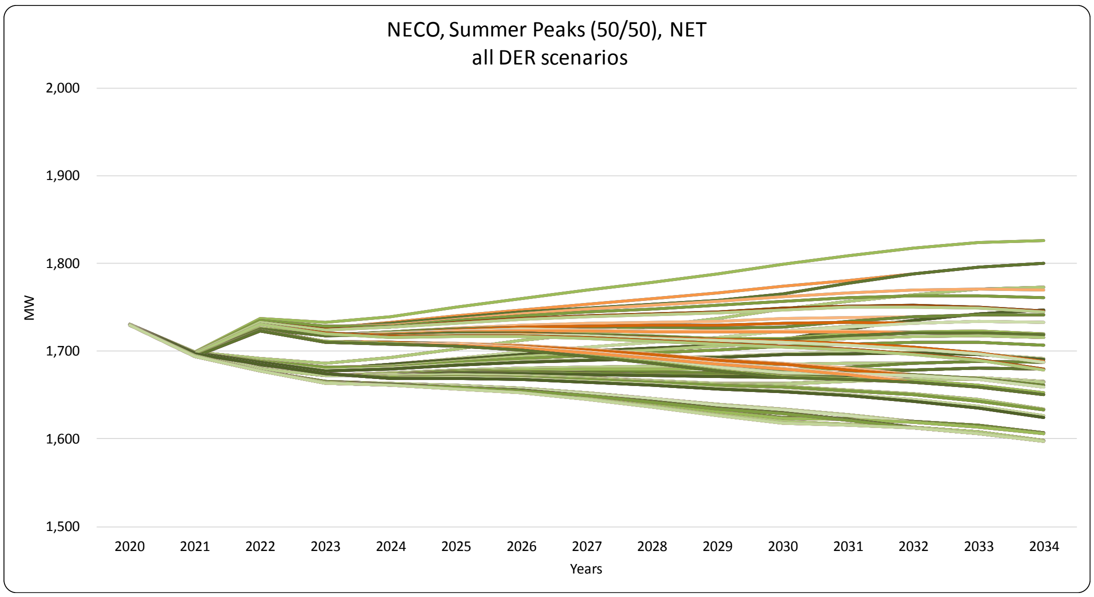


Figure 9: Summer Peaks (50/50), NET, all DER scenarios

[10] In this forecast, four DERs, each with three scenarios – base, higher and lower, creates 81 cases (3^4) for each weather scenario. With three weather scenarios 243 cases are generated for the Company.

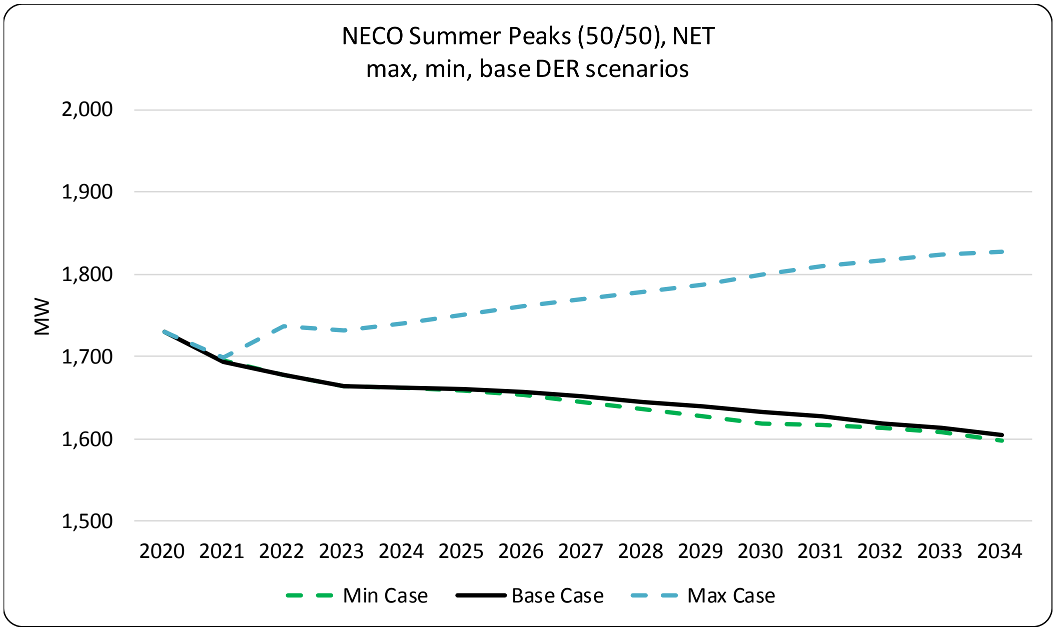


Figure 10: Annual Summer Peaks for Base Case, Maximum and Minimum Cases

Figure 10 is similar to the Figure 9, however with only the maximum, minimum and base cases shown. It should be noted that no attempt to put probabilities on these cases are made in this forecast and the likelihood of either the maximum or minimum may be low or high. Figure 10 shows that the range five years from now in year 2024 ranges from about 1,660 MW to 1,740 MW - an 80 MW spread, with the base case at 1,662 MW. The uncertainty increases over time, so that fifteen years from now in year 2034, the range expands from about 1,600 MW to about 1,825 MW, or about a 225 MW spread, with the base case at 1,606 MW. It is noted that the base case is very close to the minimum case, meaning that most of the risk is in the higher load direction. This is expected based on the DER scenarios. Specifically,

- there is no high EE case (i.e. lower loads) in Rhode Island
- there is no high DR case
- there are no energy storage scenarios
- the base and high PV case is the same in the early years. In the mid to later years, the hour of the peak moves to late evening and early night hours where PV does not have significant impact

While the figures above show what the longer term annual single summer peaks look like, Figures 11 and 12 show what the 24-hour peak day profiles might be for selected years.

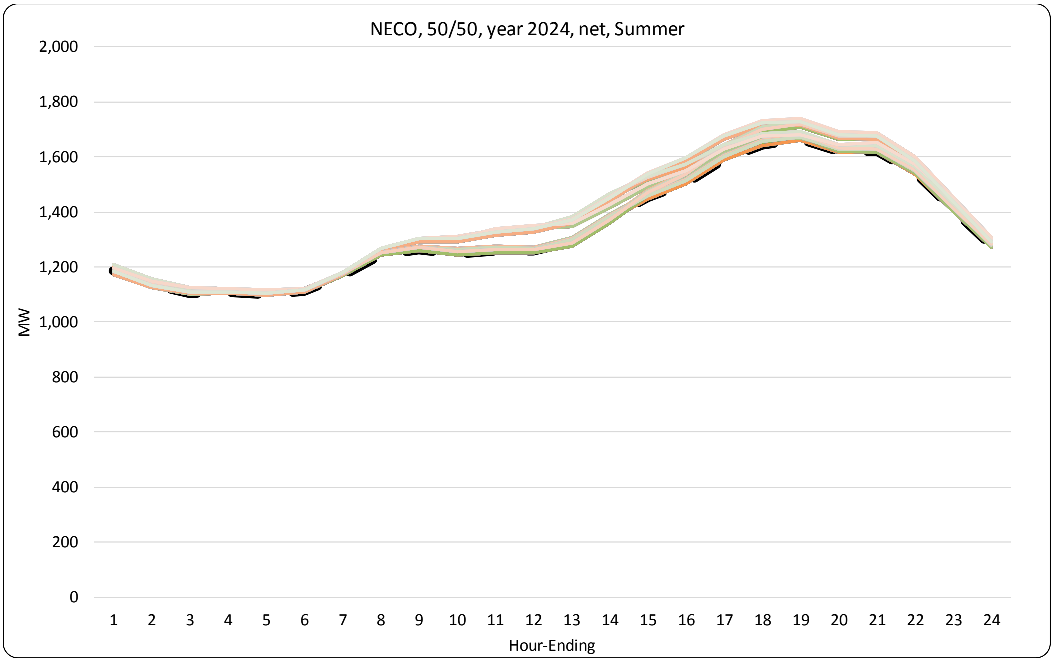


Figure 11: 50/50 case, net summer peak, w/range of DER scenarios, year 2024

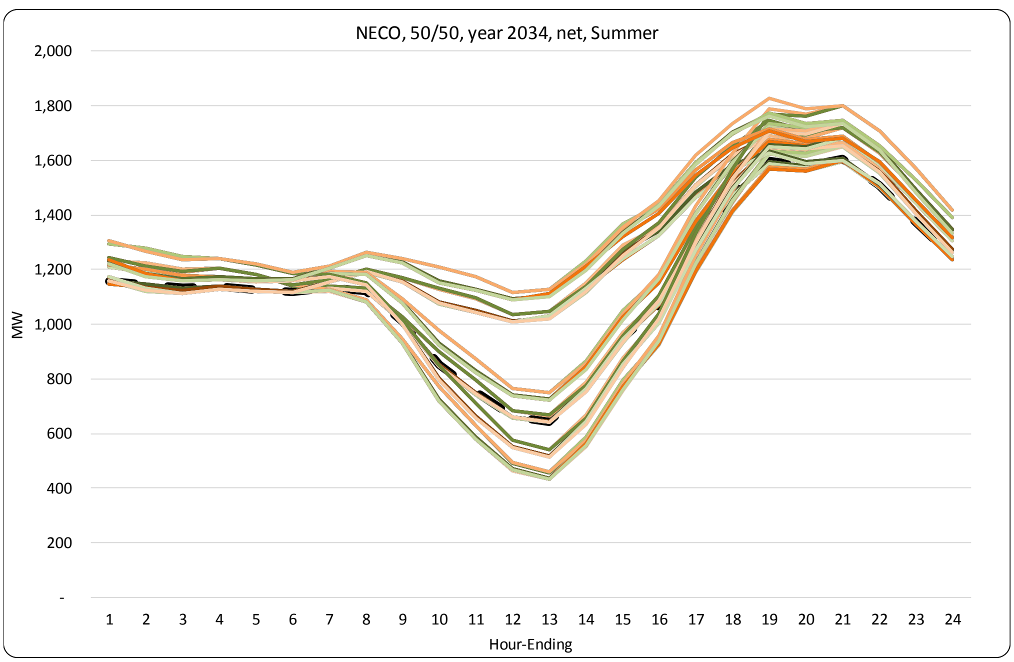


Figure 12: 50/50 case, net summer peak, w/range of DER scenarios, year 2034

What becomes apparent is that the range of possible outcomes in the early years, quickly widens fifteen years out. Note that the mid-day hours have a wider range of possible loads than other times of the day.

Appendices D and E describe the process for determining these scenarios and what the input cases look like.

The base case DER projections included in this forecast are based on current trends, approved programs, and existing state policy targets. They are considered the most probable scenario at this time. The higher and lower scenarios are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive and may or may not capture some of the more ambitious and aspirational type DER scenarios associated with more renewables due to climate and other regional discussions. These can include, among other things, additional electrification of the transportation sector and electrification of the heating sector. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely. In addition, no attempt to put probabilities on any of the base, higher or lower scenarios are made in this forecast. The Company is investigating adding probabilities for future iterations of this report. The Company is also part of Grid Modernization, more specifically in Rhode Island termed Power Sector Transformation (PST), and considers scenarios and work in that arena in this forecast as appropriate.

Appendix A: Forecast Details

NECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2003	1,670		1,815		1,965		2,008		80.1
2004	1,628	-2.5%	1,851	2.0%	2,009	2.2%	2,054	2.3%	78.5
2005	1,805	10.8%	1,784	-3.6%	1,941	-3.4%	1,986	-3.3%	83.1
2006	1,985	10.0%	1,814	1.7%	1,956	0.7%	1,994	0.4%	85.9
2007	1,777	-10.5%	1,864	2.7%	2,023	3.4%	2,068	3.7%	80.9
2008	1,824	2.6%	1,828	-1.9%	1,980	-2.1%	2,023	-2.2%	82.9
2009	1,713	-6.1%	1,829	0.1%	2,004	1.2%	2,054	1.5%	80.3
2010	1,872	9.3%	1,812	-1.0%	1,986	-0.9%	2,035	-0.9%	84.5
2011	1,974	5.5%	1,831	1.0%	2,003	0.9%	2,052	0.8%	84.8
2012	1,892	-4.2%	1,835	0.2%	1,993	-0.5%	2,038	-0.7%	83.5
2013	1,965	3.9%	1,831	-0.2%	2,003	0.5%	2,052	0.7%	84.7
2014	1,653	-15.9%	1,824	-0.4%	1,998	-0.2%	2,048	-0.2%	80.4
2015	1,738	5.1%	1,865	2.2%	2,053	2.8%	2,107	2.9%	80.4
2016	1,803	3.8%	1,791	-3.9%	1,964	-4.3%	2,013	-4.4%	82.6
2017	1,688	-6.4%	1,737	-3.0%	1,910	-2.7%	1,960	-2.7%	81.7
2018	1,847	9.4%	1,785	2.8%	1,961	2.6%	2,010	2.6%	83.4
2019	1,750	-5.3%	1,753	-1.8%	1,957	-0.2%	2,015	0.2%	84.5
2020	-	-	1,730	-1.3%	1,943	-0.7%	2,003	-0.6%	-
2021	-	-	1,694	-2.1%	1,905	-2.0%	1,965	-1.9%	-
2022	-	-	1,678	-1.0%	1,892	-0.7%	1,953	-0.6%	-
2023	-	-	1,665	-0.8%	1,878	-0.7%	1,940	-0.7%	-
2024	-	-	1,662	-0.1%	1,875	-0.2%	1,935	-0.3%	-
2025	-	-	1,660	-0.1%	1,876	0.1%	1,937	0.1%	-
2026	-	-	1,657	-0.2%	1,876	0.0%	1,938	0.0%	-
2027	-	-	1,652	-0.3%	1,873	-0.2%	1,936	-0.1%	-
2028	-	-	1,645	-0.4%	1,869	-0.2%	1,932	-0.2%	-
2029	-	-	1,639	-0.4%	1,864	-0.2%	1,928	-0.2%	-
2030	-	-	1,633	-0.3%	1,861	-0.2%	1,926	-0.2%	-
2031	-	-	1,627	-0.4%	1,856	-0.3%	1,921	-0.2%	-
2032	-	-	1,619	-0.5%	1,849	-0.3%	1,915	-0.3%	-
2033	-	-	1,614	-0.3%	1,841	-0.5%	1,907	-0.4%	-
2034	-	-	1,605	-0.5%	1,828	-0.7%	1,894	-0.6%	-

	50/50	90/10	
Avg, last 15 yrs	-0.4%	-0.2%	-0.1%
Avg. last 10 yrs	-0.4%	-0.2%	-0.2%
Avg. last 5 yrs	-0.8%	-0.4%	-0.3%
BASE 2019			
Avg. next 5 yrs	-1.1%	-0.9%	-0.8%
Avg. next 10 yrs	-0.7%	-0.5%	-0.4%
Avg. next 15 yrs	-0.6%	-0.5%	-0.4%

WTHI

NORMAL	82.4
EXTREME 90/ 10	85.3
EXTREME 95/ 5	86.1

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage and company demand response***

NECO	SUMMER 50/50 Peaks (MW) (before & after DERs)																			
	SYSTEM PEAK							DER IMPACTS						% of reconstituted peaks						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	DER	EE	PV	EV	DR	ES	DER
2003	1,824	1,815	1,824	1,824	1,824	1,824	**1,815**	9	0	0.0	0.0	0.0	9	0.5%	0.0%	0.0%	0.0%	0.0%	0.5%
2004	1,872	1,851	1,872	1,872	1,872	1,872	**1,851**	21	0	0.0	0.0	0.0	21	1.1%	0.0%	0.0%	0.0%	0.0%	1.1%
2005	1,814	1,784	1,814	1,814	1,814	1,814	**1,784**	30	0	0.0	0.0	0.0	30	1.7%	0.0%	0.0%	0.0%	0.0%	1.7%
2006	1,856	1,815	1,855	1,856	1,856	1,856	**1,814**	41	0	0.0	0.0	0.0	41	2.2%	0.0%	0.0%	0.0%	0.0%	2.2%
2007	1,915	1,864	1,915	1,915	1,915	1,915	**1,864**	51	0	0.0	0.0	0.0	51	2.7%	0.0%	0.0%	0.0%	0.0%	2.7%
2008	1,890	1,829	1,890	1,890	1,890	1,890	**1,828**	61	0	0.0	0.0	0.0	62	3.2%	0.0%	0.0%	0.0%	0.0%	3.3%
2009	1,907	1,830	1,906	1,907	1,907	1,907	**1,829**	77	1	0.0	0.0	0.0	77	4.0%	0.0%	0.0%	0.0%	0.0%	4.0%
2010	1,901	1,812	1,901	1,901	1,901	1,901	**1,812**	89	1	0.0	0.0	0.0	90	4.7%	0.0%	0.0%	0.0%	0.0%	4.7%
2011	1,933	1,832	1,932	1,933	1,933	1,933	**1,831**	102	1	0.0	0.0	0.0	103	5.3%	0.1%	0.0%	0.0%	0.0%	5.3%
2012	1,957	1,836	1,955	1,957	1,957	1,957	**1,835**	121	2	0.0	0.0	0.0	123	6.2%	0.1%	0.0%	0.0%	0.0%	6.3%
2013	1,988	1,840	1,979	1,988	1,988	1,988	**1,831**	148	9	0.0	0.0	0.0	157	7.4%	0.4%	0.0%	0.0%	0.0%	7.9%
2014	2,021	1,835	2,011	2,021	2,021	2,021	**1,824**	187	11	0.0	0.0	0.0	197	9.2%	0.5%	0.0%	0.0%	0.0%	9.8%
2015	2,100	1,880	2,085	2,100	2,100	2,100	**1,865**	220	16	0.1	0.0	0.0	236	10.5%	0.7%	0.0%	0.0%	0.0%	11.2%
2016	2,064	1,813	2,042	2,064	2,064	2,064	**1,791**	250	22	0.1	0.0	0.0	272	12.1%	1.1%	0.0%	0.0%	0.0%	13.2%
2017	2,062	1,782	2,025	2,062	2,053	2,062	**1,737**	280	37	0.1	8.3	0.0	325	13.6%	1.8%	0.0%	0.4%	0.0%	15.8%
2018	2,165	1,857	2,116	2,165	2,142	2,165	**1,785**	308	49	0.2	22.8	0.0	379	14.2%	2.3%	0.0%	1.1%	0.0%	17.5%
2019	2,172	1,834	2,118	2,172	2,145	2,172	**1,753**	338	54	0.4	27.3	0.0	418	15.6%	2.5%	0.0%	1.3%	0.0%	19.3%
2020	2,269	1,903	2,134	2,270	2,232	2,269	**1,730**	367	136	0.5	37.7	0.0	540	16.2%	6.0%	0.0%	1.7%	0.0%	23.8%
2021	2,238	1,842	2,134	2,239	2,193	2,238	**1,694**	395	104	0.8	45.0	0.0	544	17.7%	4.6%	0.0%	2.0%	0.0%	24.3%
2022	2,273	1,851	2,144	2,274	2,228	2,273	**1,678**	422	129	1.0	45.7	0.0	596	18.6%	5.7%	0.0%	2.0%	0.0%	26.2%
2023	2,209	1,762	2,156	2,212	2,163	2,209	**1,665**	447	54	2.4	46.5	0.0	545	20.2%	2.4%	0.1%	2.1%	0.0%	24.7%
2024	2,239	1,768	2,177	2,242	2,192	2,239	**1,662**	471	62	3.1	47.2	0.0	577	21.0%	2.8%	0.1%	2.1%	0.0%	25.8%
2025	2,268	1,774	2,198	2,272	2,220	2,268	**1,660**	494	70	3.8	47.9	0.0	608	21.8%	3.1%	0.2%	2.1%	0.0%	26.8%
2026	2,294	1,778	2,217	2,298	2,245	2,294	**1,657**	515	77	4.6	48.6	0.0	637	22.5%	3.4%	0.2%	2.1%	0.0%	27.8%
2027	2,316	1,780	2,232	2,322	2,267	2,316	**1,652**	536	84	5.4	49.4	0.0	664	23.1%	3.6%	0.2%	2.1%	0.0%	28.7%
2028	2,336	1,780	2,245	2,342	2,286	2,336	**1,645**	556	91	6.4	50.1	0.0	691	23.8%	3.9%	0.3%	2.1%	0.0%	29.6%
2029	2,354	1,780	2,256	2,361	2,303	2,354	**1,639**	574	98	7.4	50.8	0.0	715	24.4%	4.1%	0.3%	2.2%	0.0%	30.4%
2030	2,372	1,780	2,268	2,380	2,320	2,372	**1,633**	592	104	8.5	51.5	0.0	739	24.9%	4.4%	0.4%	2.2%	0.0%	31.1%
2031	2,387	1,779	2,278	2,397	2,335	2,387	**1,627**	608	110	9.6	52.2	0.0	761	25.5%	4.6%	0.4%	2.2%	0.0%	31.9%
2032	2,285	1,661	2,285	2,296	2,233	2,285	**1,619**	624	0	10.9	52.8	0.0	666	27.3%	0.0%	0.5%	2.3%	0.0%	29.2%
2033	2,295	1,655	2,295	2,307	2,242	2,295	**1,614**	640	0	11.9	53.4	0.0	681	27.9%	0.0%	0.5%	2.3%	0.0%	29.7%
2034	2,300	1,647	2,300	2,313	2,247	2,300	**1,605**	654	0	12.8	54.0	0.0	695	28.4%	0.0%	0.6%	2.3%	0.0%	30.2%

Avg, last 15 yrs	1.0%	-0.1%	0.8%	1.0%	0.9%	1.0%	**-0.4%**
Avg. last 10 yrs	1.3%	0.0%	1.1%	1.3%	1.2%	1.3%	**-0.4%**
Avg. last 5 yrs	1.4%	0.0%	1.0%	1.4%	1.2%	1.4%	**-0.8%**
BASE 2019							
Avg. next 5 yrs	0.6%	-0.7%	0.6%	0.6%	0.4%	0.6%	**-1.1%**
Avg. next 10 yrs	0.8%	-0.3%	0.6%	0.8%	0.7%	0.8%	**-0.7%**
Avg. next 15 yrs	0.4%	-0.7%	0.6%	0.4%	0.3%	0.4%	**-0.6%**

EE: Energy Efficiency
PV: Solar - Photovoltaics
EV: Electric Vehicles
DR: Demand Response (Company only)
ES: Energy Storage

NECO
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2003	1,389		1,389		1,389		1,389		55.7
2004	1,394	0.4%	1,428	2.8%	1,484	6.8%	1,500	7.9%	36.7
2005	1,329	-4.6%	1,324	-7.3%	1,375	-7.3%	1,390	-7.3%	45.0
2006	1,329	0.0%	1,317	-0.5%	1,369	-0.5%	1,384	-0.4%	45.5
2007	1,352	1.7%	1,327	0.8%	1,378	0.6%	1,392	0.6%	44.8
2008	1,305	-3.5%	1,317	-0.8%	1,371	-0.5%	1,387	-0.4%	40.0
2009	1,294	-0.8%	1,328	0.9%	1,386	1.1%	1,402	1.1%	35.0
2010	1,315	1.6%	1,265	-4.8%	1,324	-4.5%	1,340	-4.4%	53.1
2011	1,243	-5.5%	1,251	-1.1%	1,309	-1.1%	1,325	-1.1%	41.6
2012	1,320	6.2%	1,290	3.1%	1,347	3.0%	1,364	2.9%	51.9
2013	1,328	0.7%	1,324	2.6%	1,382	2.6%	1,399	2.6%	43.9
2014	1,275	-4.0%	1,229	-7.1%	1,288	-6.8%	1,305	-6.7%	52.2
2015	1,223	-4.1%	1,201	-2.3%	1,255	-2.6%	1,270	-2.7%	55.0
2016	1,239	1.3%	1,278	6.4%	1,344	7.1%	1,362	7.3%	35.9
2017	1,277	3.1%	1,206	-5.6%	1,283	-4.5%	1,305	-4.2%	53.8
2018	1,301	1.9%	1,250	3.7%	1,320	2.9%	1,340	2.6%	51.0
2019	-	-	1,234	-1.3%	1,305	-1.2%	1,325	-1.1%	-
2020	-	-	1,214	-1.6%	1,287	-1.4%	1,307	-1.4%	-
2021	-	-	1,196	-1.5%	1,270	-1.3%	1,291	-1.2%	-
2022	-	-	1,180	-1.4%	1,255	-1.2%	1,277	-1.1%	-
2023	-	-	1,165	-1.2%	1,242	-1.0%	1,264	-1.0%	-
2024	-	-	1,152	-1.1%	1,231	-0.9%	1,253	-0.9%	-
2025	-	-	1,141	-1.0%	1,221	-0.8%	1,243	-0.8%	-
2026	-	-	1,130	-0.9%	1,212	-0.7%	1,235	-0.7%	-
2027	-	-	1,122	-0.8%	1,205	-0.6%	1,229	-0.6%	-
2028	-	-	1,114	-0.7%	1,199	-0.5%	1,223	-0.4%	-
2029	-	-	1,108	-0.6%	1,194	-0.4%	1,219	-0.3%	-
2030	-	-	1,103	-0.4%	1,191	-0.3%	1,216	-0.3%	-
2031	-	-	1,099	-0.4%	1,188	-0.2%	1,214	-0.2%	-
2032	-	-	1,096	-0.3%	1,187	-0.1%	1,212	-0.1%	-
2033	-	-	1,094	-0.2%	1,186	-0.1%	1,212	0.0%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg, last 15 yrs	-0.7%	-0.3%	-0.2%
Avg. last 10 yrs	-0.5%	-0.4%	-0.3%
Avg. last 5 yrs	-1.1%	-0.9%	-0.9%
BASE 2018			
Avg. next 5 yrs	-1.4%	-1.2%	-1.2%
Avg. next 10 yrs	-1.1%	-1.0%	-0.9%
Avg. next 14 yrs	-0.9%	-0.8%	-0.7%

HDD_wtd

NORMAL	43.8
EXTREME 90/10	54.7
EXTREME 95/5	57.8

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage and company demand response (solar and demand response are zero at times of winter peak)***

Appendix B: Historical Peaks Days and Hours

Summer Peaks

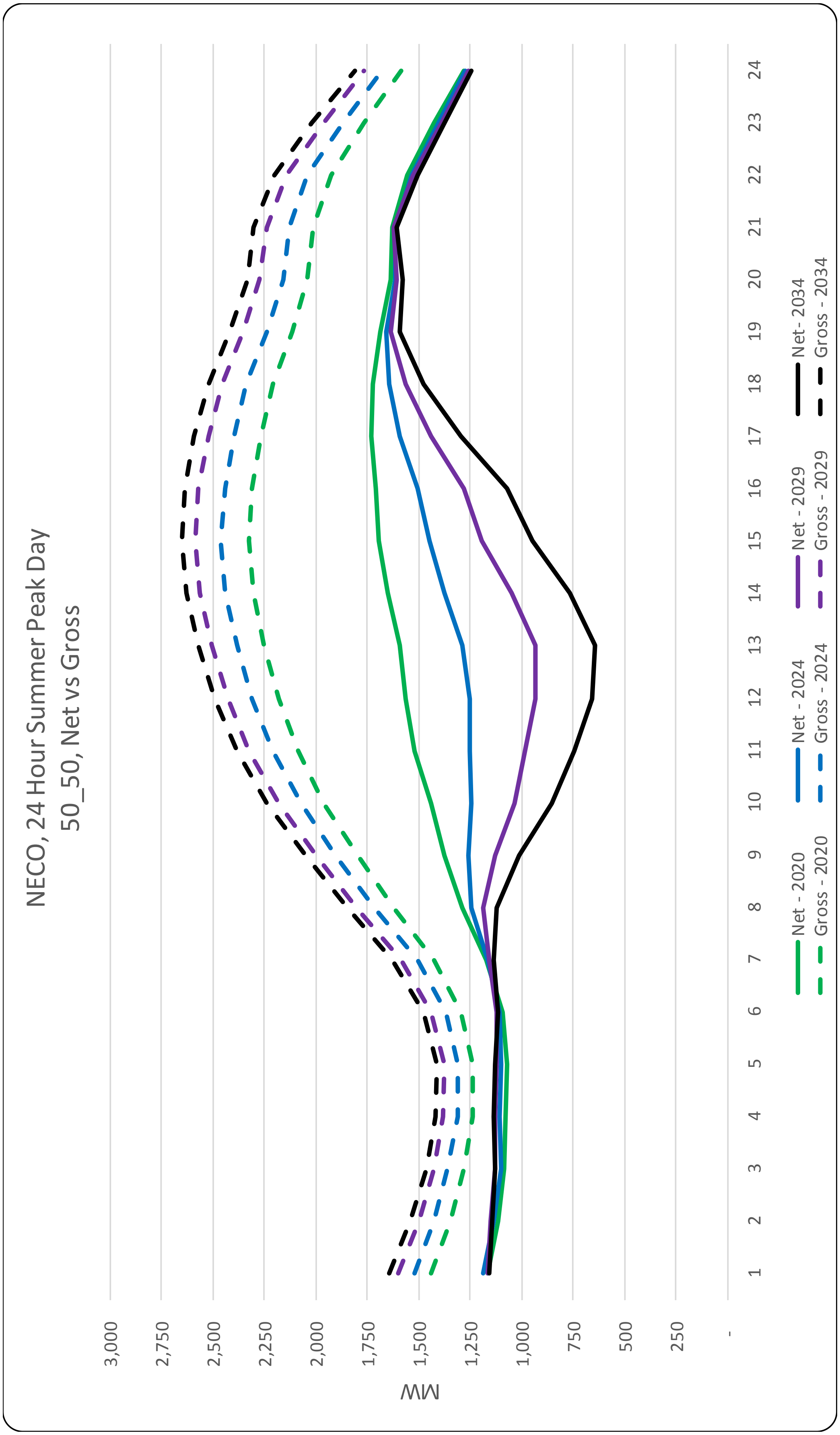
Year	Date	Hour-Ending
2003	8/22/2003	15
2004	8/30/2004	15
2005	8/5/2005	15
2006	8/2/2006	15
2007	8/3/2007	15
2008	6/10/2008	15
2009	8/18/2009	15
2010	7/6/2010	15
2011	7/22/2011	16
2012	7/18/2012	15
2013	7/19/2013	15
2014	9/2/2014	16
2015	7/20/2015	15
2016	8/12/2016	16
2017	7/20/2017	16
2018	8/29/2018	17
2019	7/21/2019	18

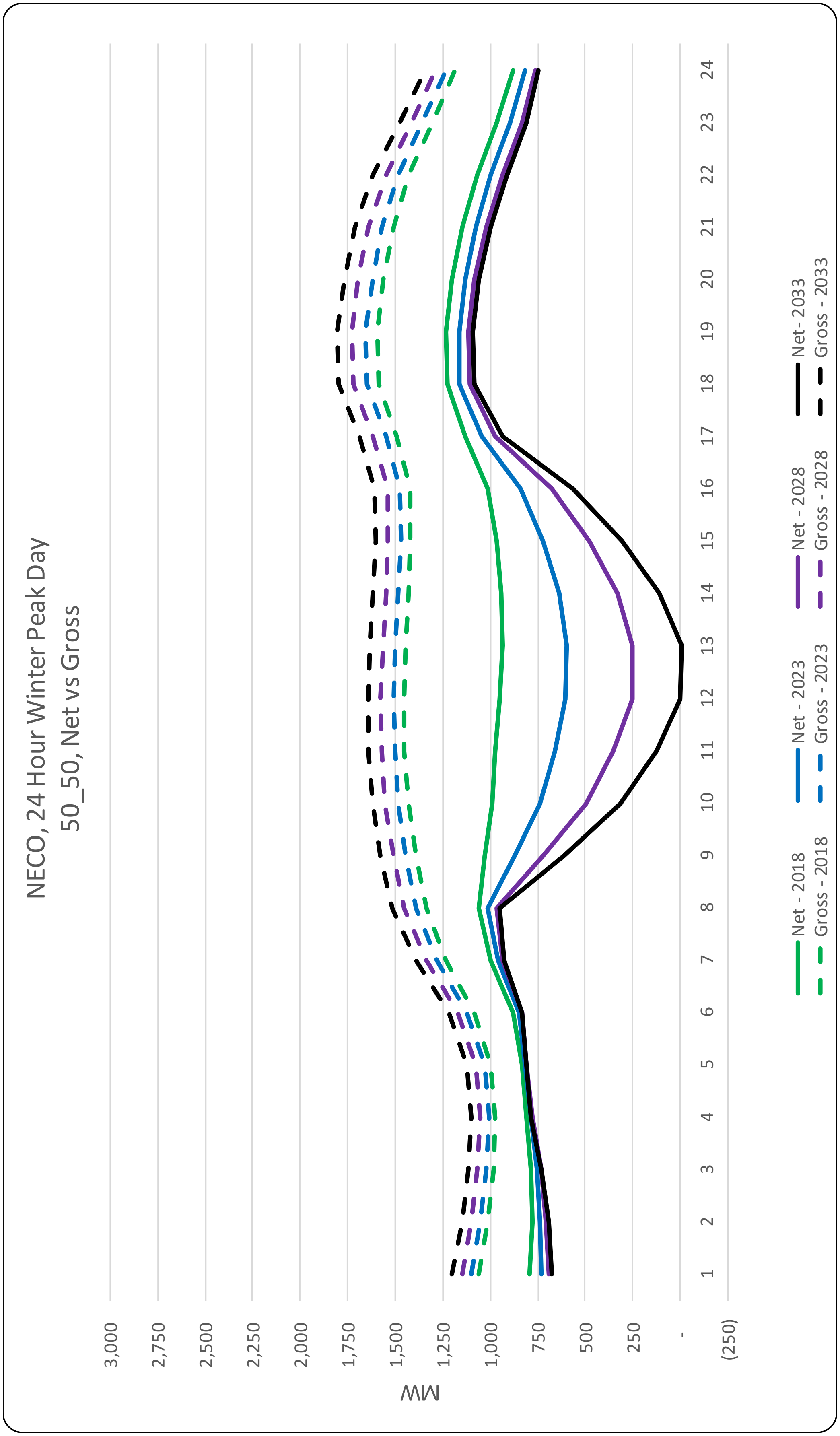
Winter Peaks

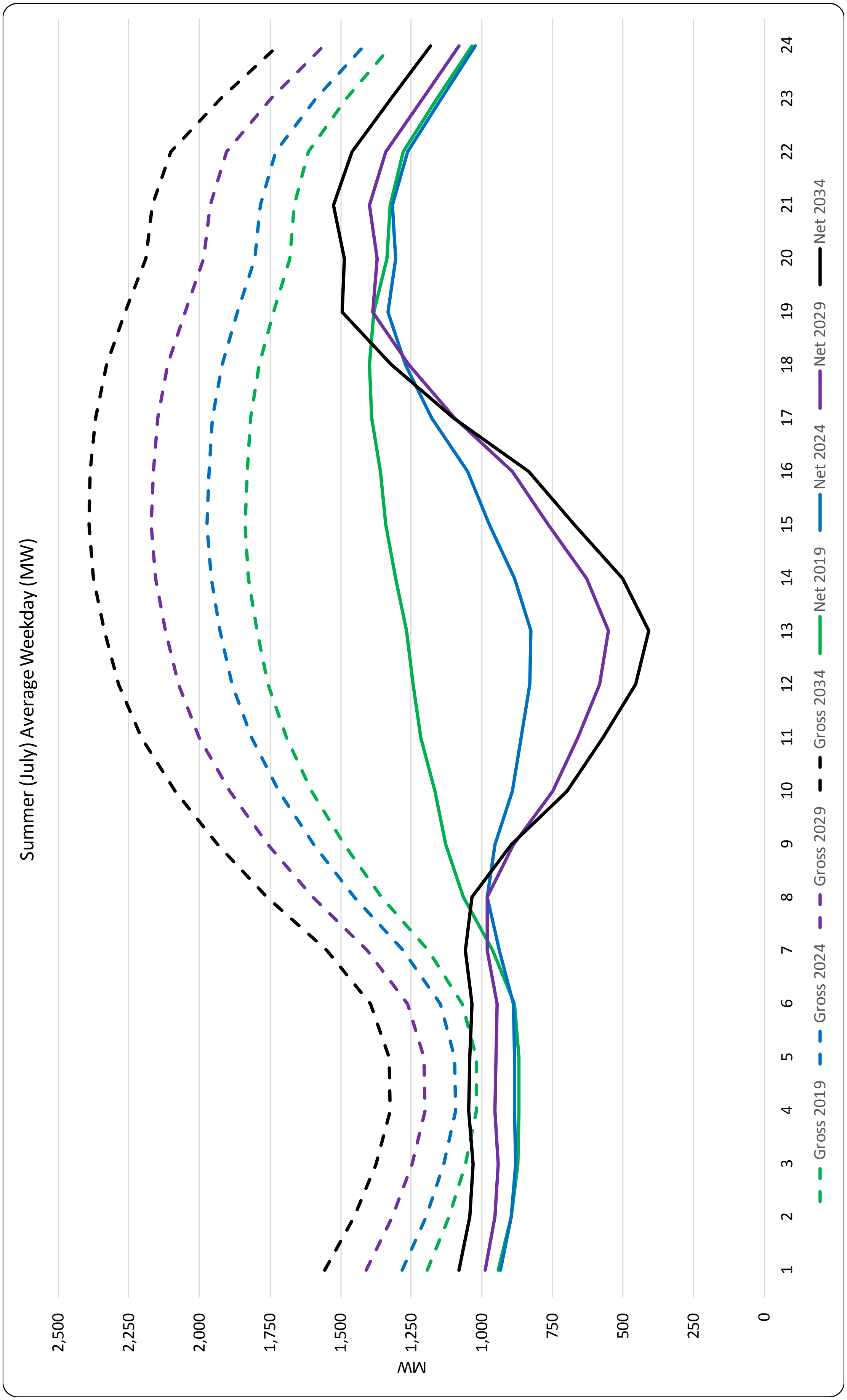
Year	Date	Hour-Ending
2003-04	1/15/2004	19
2004-05	12/20/2004	19
2005-06	12/14/2005	18
2006-07	2/5/2007	19
2007-08	1/3/2008	19
2008-09	12/8/2008	18
2009-10	12/29/2009	19
2010-11	1/24/2011	19
2011-12	1/4/2012	18
2012-13	1/24/2013	19
2013-14	12/17/2013	18
2014-15	1/8/2015	18
2015-16	2/15/2016	19
2016-17	12/15/2016	18
2017-18	1/2/2018	19
2018-19	1/21/2019	18

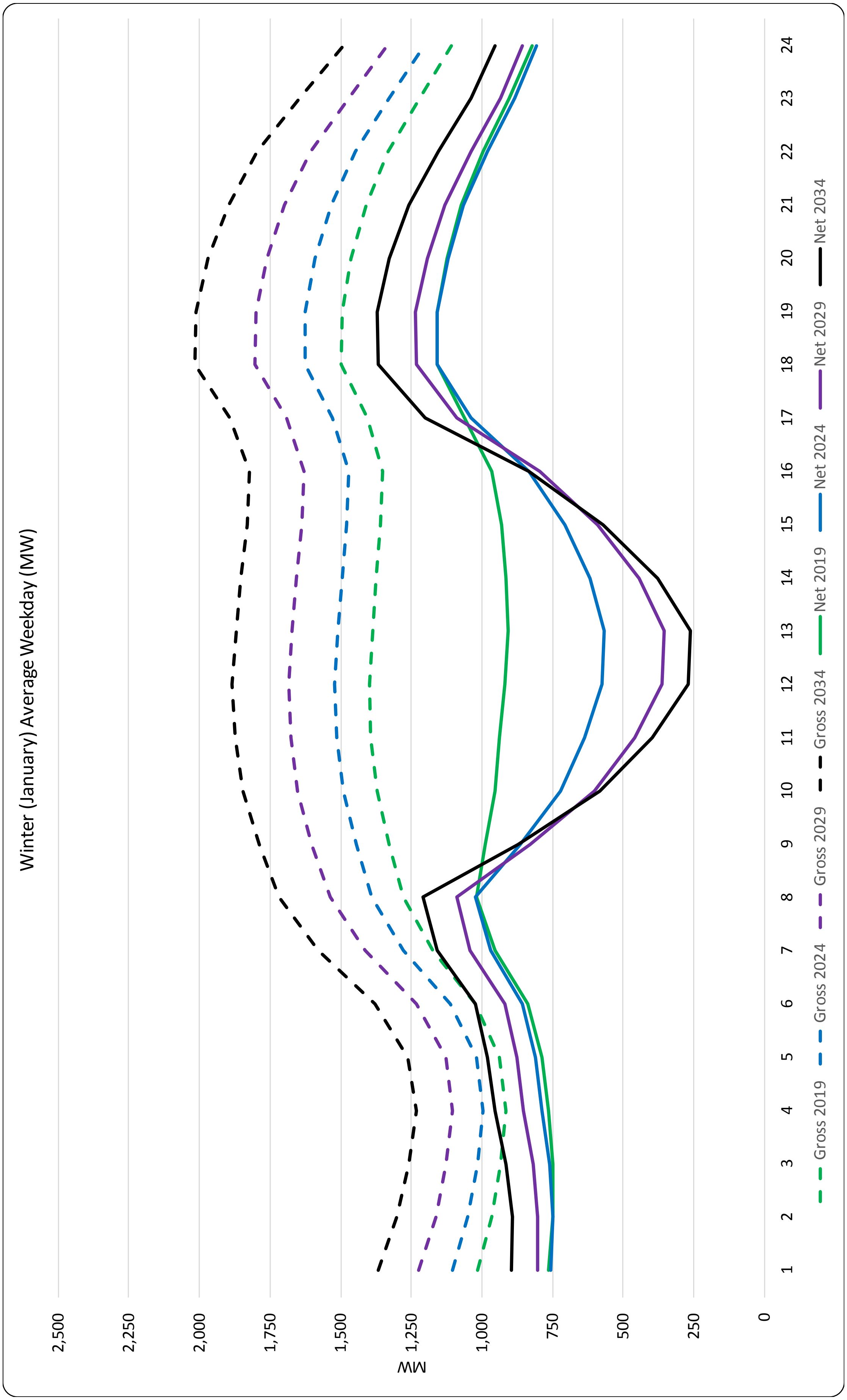
Appendix C: Load Shapes for Typical Day Types

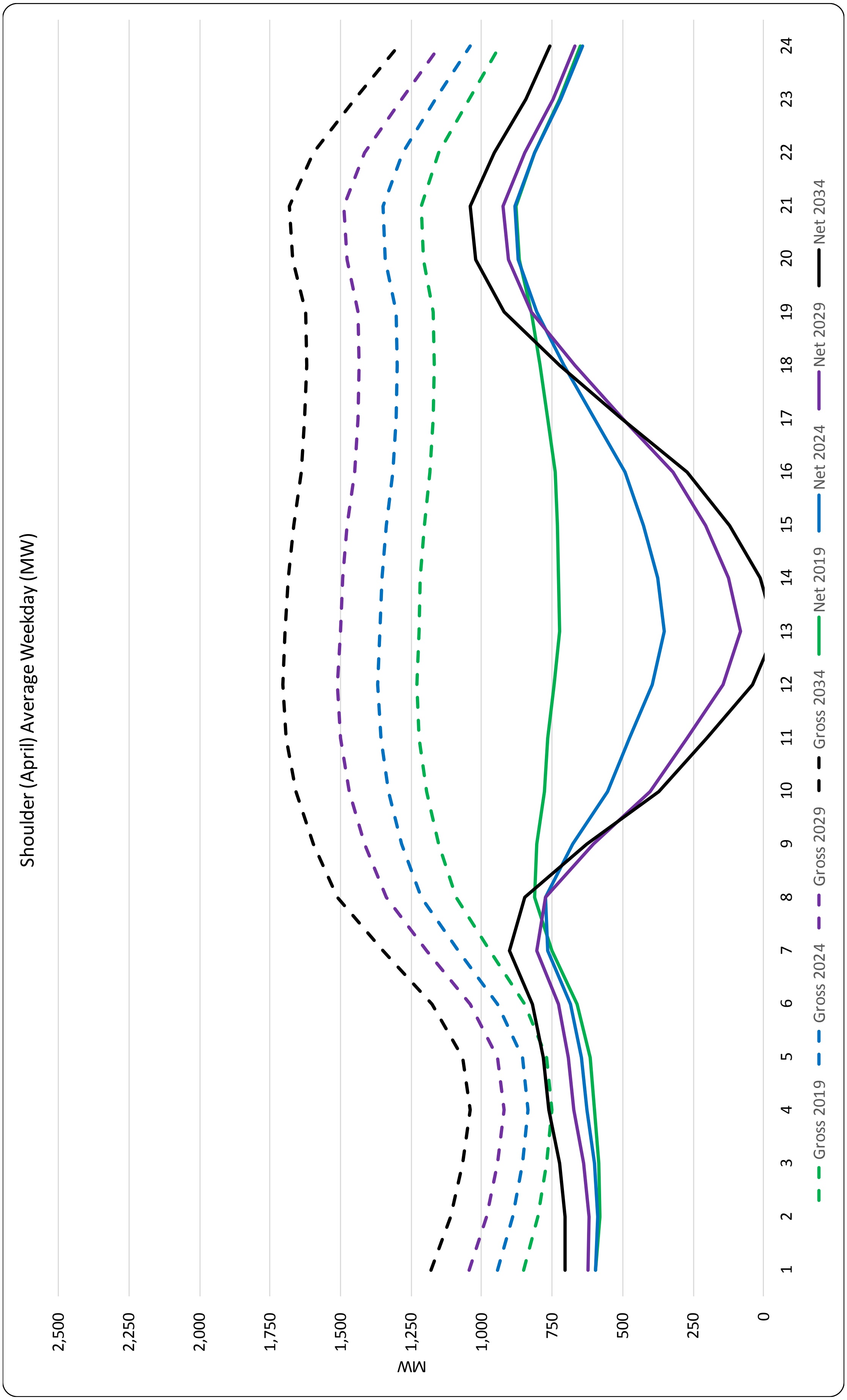
(for Base Case)

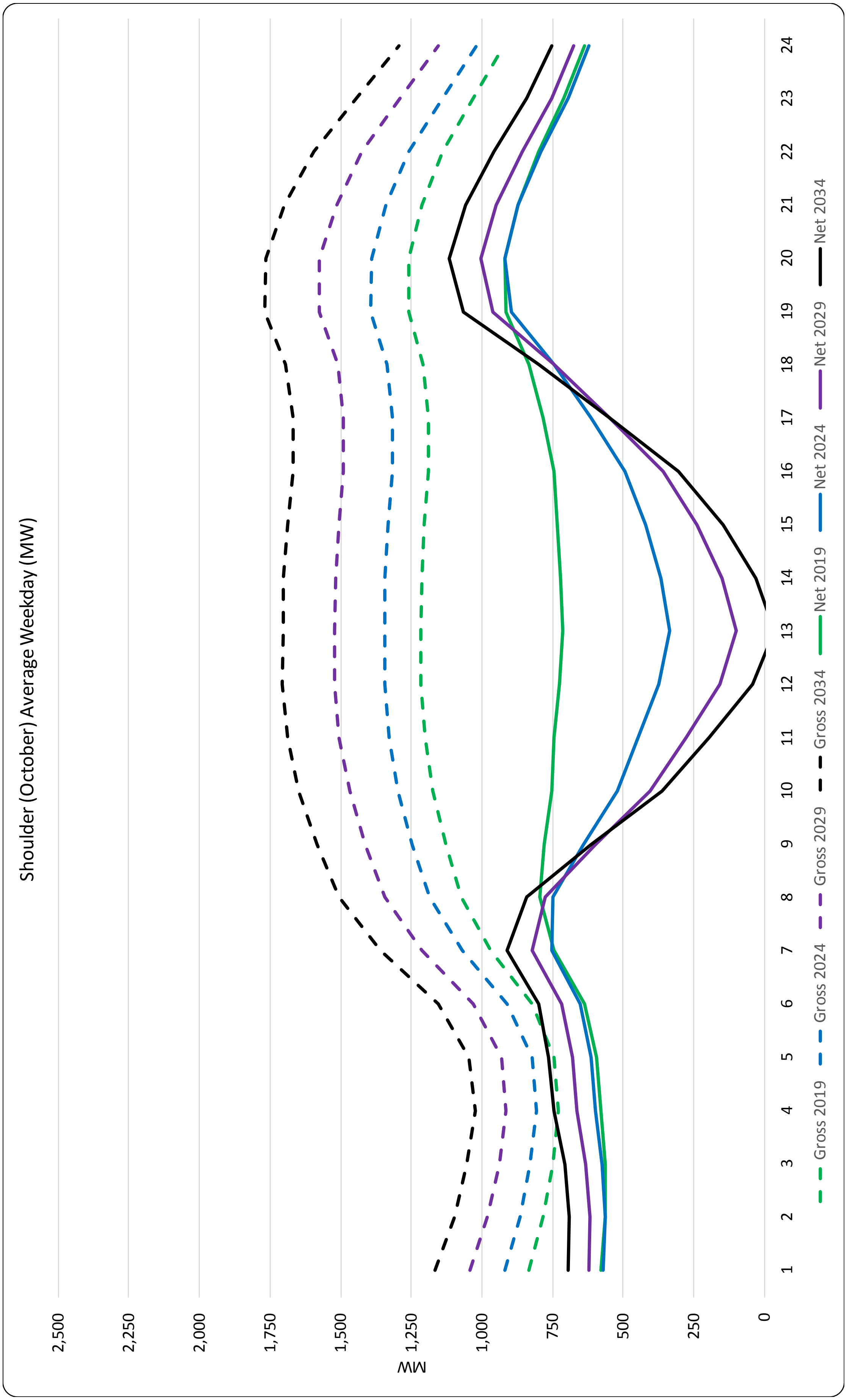

NECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
3,000
2,750
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
-
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2020
Gross - 2020
Net - 2024
Gross - 2024
Net - 2029
Gross - 2029
Net - 2034
Gross - 2034

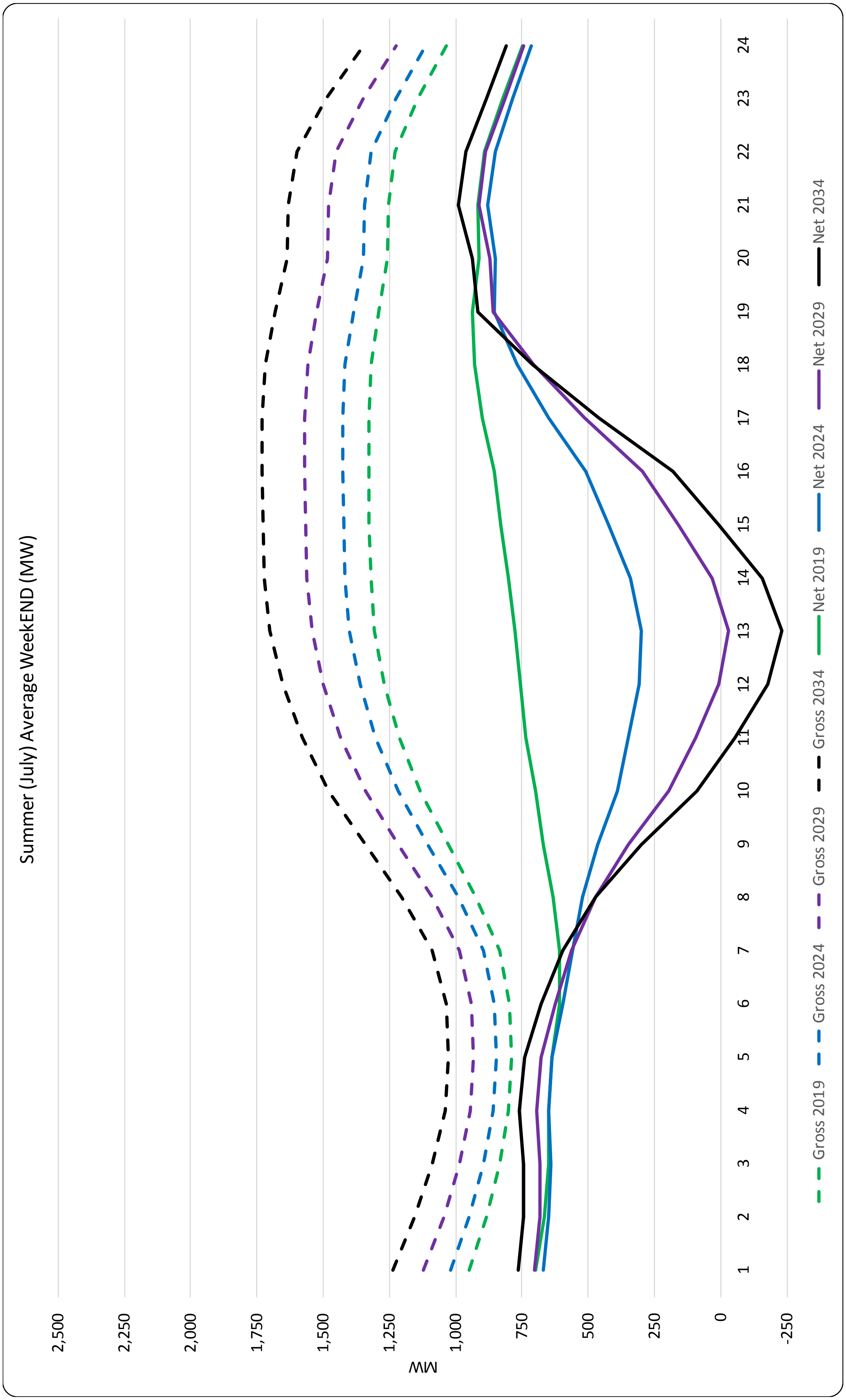

NECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
MW
3,000
2,750
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
-
(250)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Net - 2018
Gross - 2018
Net - 2023
Gross - 2023
Net - 2028
Gross - 2028
Net - 2033
Gross - 2033

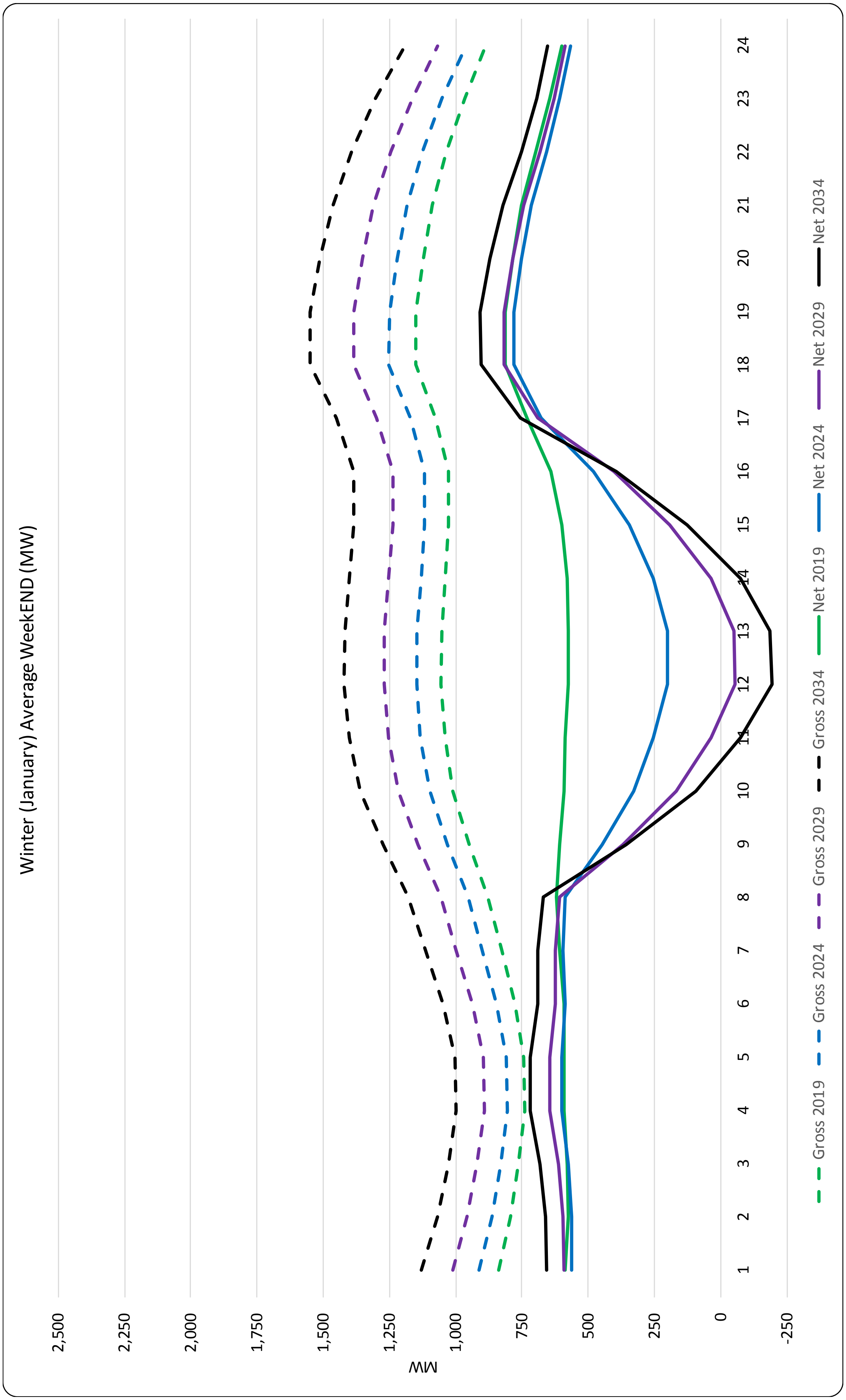

Summer (July) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

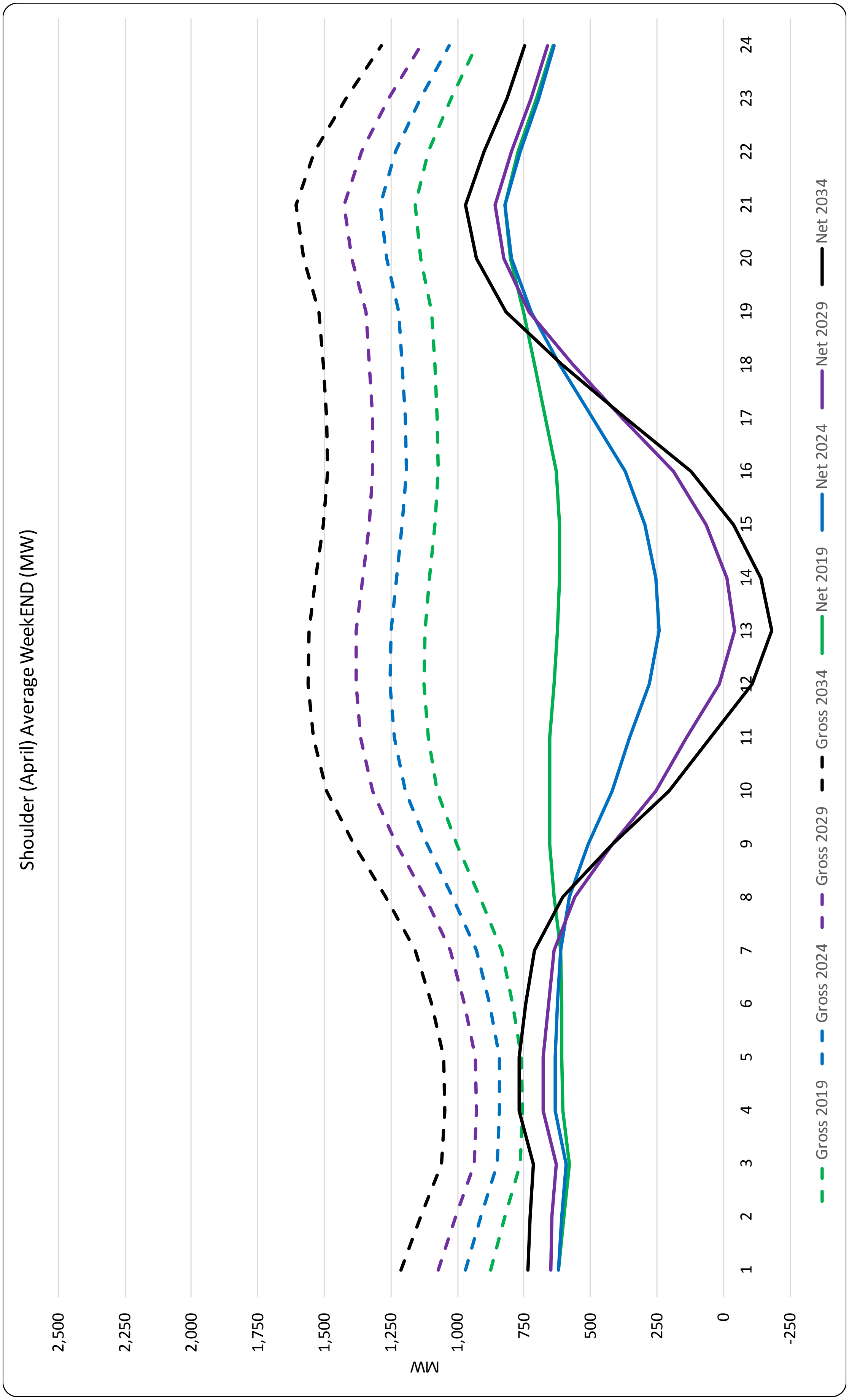

Winter (January) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


Shoulder (April) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

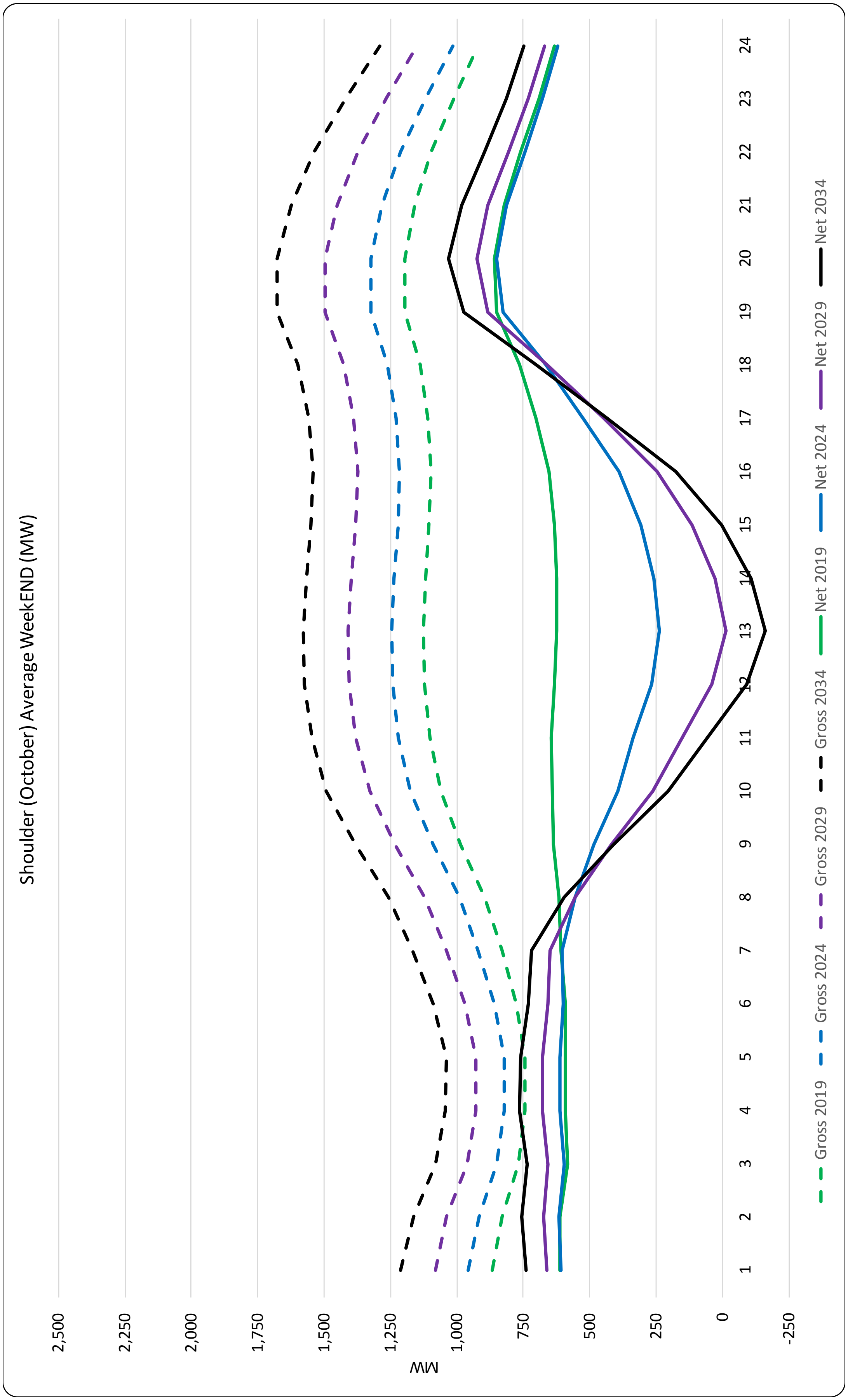

Shoulder (October) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


Summer (July) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


Winter (January) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


Shoulder (April) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

34

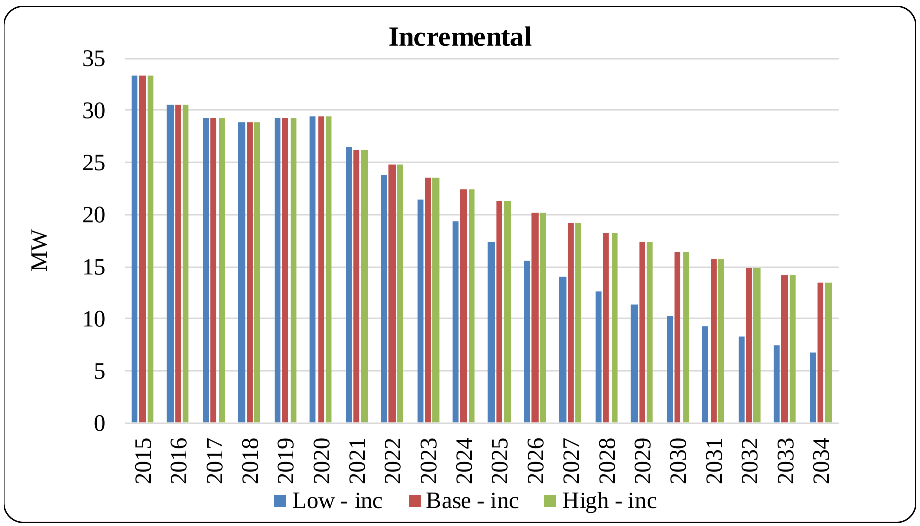

Shoulder (October) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

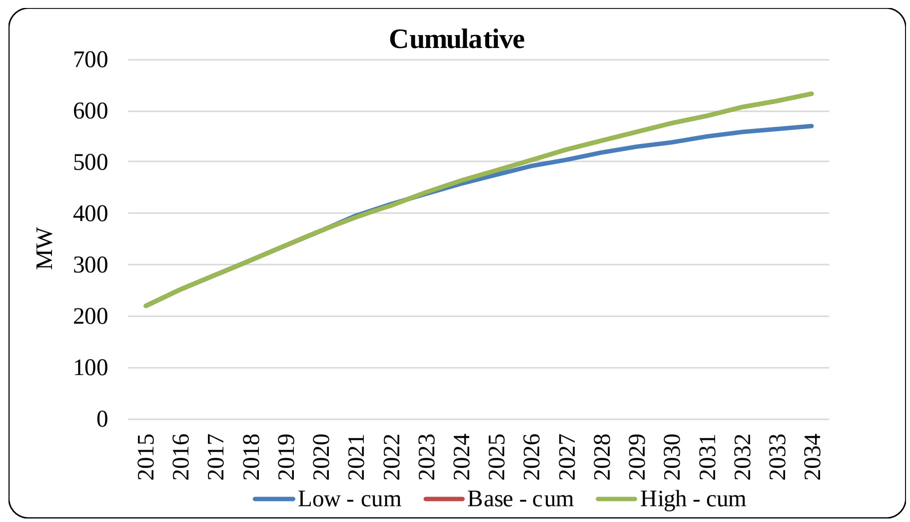
35

Appendix D: DER Scenarios Inputs

Energy Efficiency (NECO)

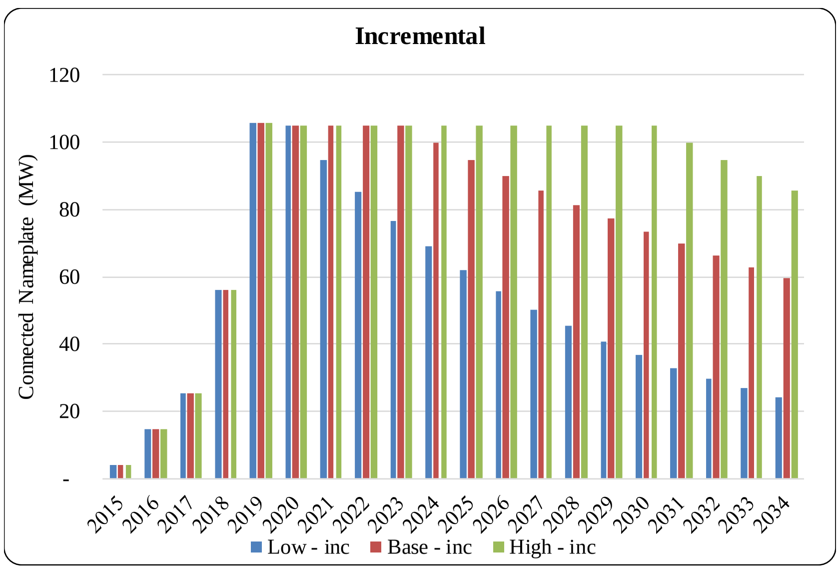
Summer Peak MWs						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2015	33.3	219.9	33.3	219.9	33.3	219.9
2016	30.5	250.4	30.5	250.4	30.5	250.4
2017	29.4	279.8	29.4	279.8	29.4	279.8
2018	28.8	308.6	28.8	307.7	28.8	307.7
2019	29.3	337.9	29.3	336.7	29.3	336.7
2020	29.4	367.3	29.4	365.7	29.4	365.7
2021	26.5	393.8	26.2	391.8	26.2	391.8
2022	23.8	417.7	24.9	416.7	24.9	416.7
2023	21.5	439.1	23.6	440.3	23.6	440.3
2024	19.3	458.4	22.4	462.8	22.4	462.8
2025	17.4	475.8	21.3	484.1	21.3	484.1
2026	15.6	491.5	20.3	504.3	20.3	504.3
2027	14.1	505.5	19.2	523.6	19.2	523.6
2028	12.7	518.2	18.3	541.8	18.3	541.8
2029	11.4	529.6	17.4	559.2	17.4	559.2
2030	10.3	539.9	16.5	575.7	16.5	575.7
2031	9.2	549.1	15.7	591.4	15.7	591.4
2032	8.3	557.4	14.9	606.3	14.9	606.3
2033	7.5	564.9	14.1	620.4	14.1	620.4
2034	6.7	571.6	13.4	633.8	13.4	633.8

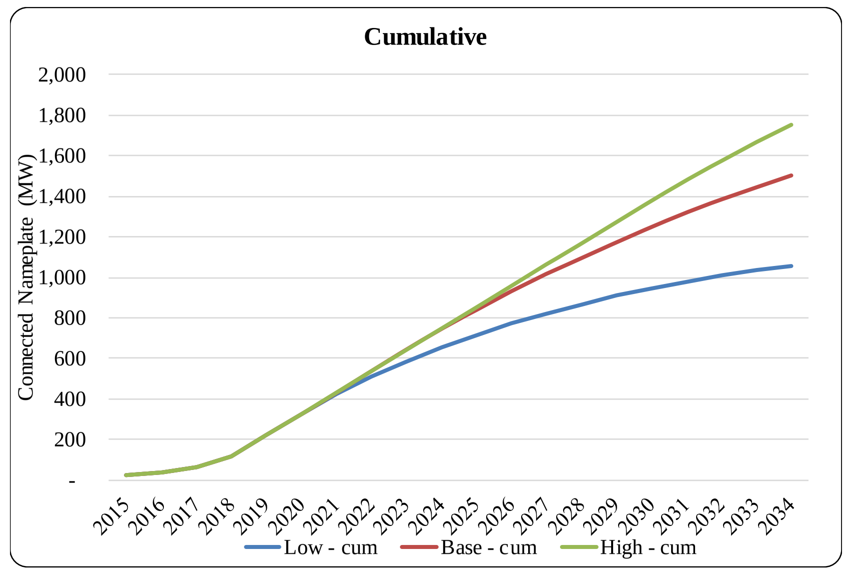




Solar – PV (NECO)

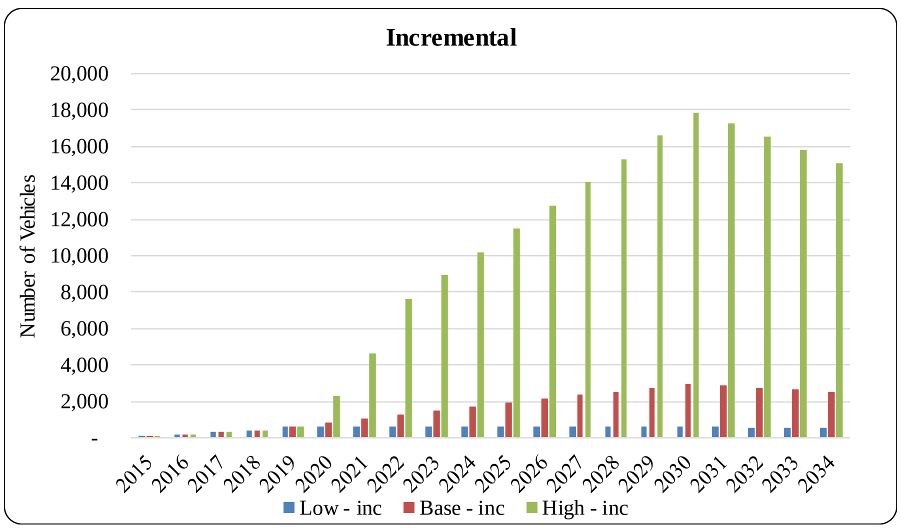
Connected Nameplate (MW)						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2015	4	22	4	22	4	22
2016	15	37	15	37	15	37
2017	25	62	25	62	25	62
2018	56	118	56	118	56	118
2019	106	224	106	224	106	224
2020	105	329	105	329	105	329
2021	95	424	105	434	105	434
2022	85	509	105	539	105	539
2023	77	585	105	644	105	644
2024	69	654	100	744	105	749
2025	62	716	95	839	105	855
2026	56	772	90	929	105	960
2027	50	822	86	1,015	105	1,065
2028	45	868	81	1,096	105	1,170
2029	41	908	77	1,173	105	1,275
2030	37	945	73	1,247	105	1,380
2031	33	978	70	1,317	100	1,480
2032	30	1,008	66	1,383	95	1,575
2033	27	1,035	63	1,446	90	1,665
2034	24	1,059	60	1,506	86	1,751

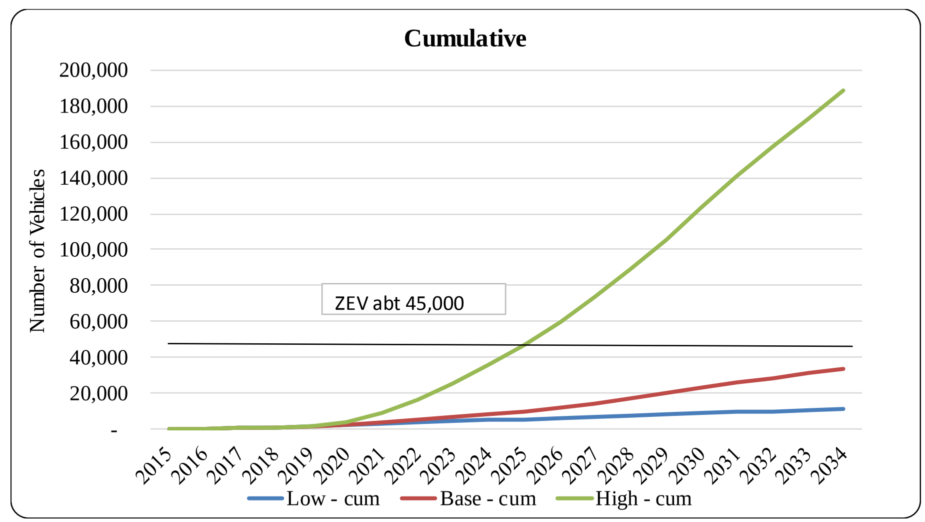




Electric Vehicles (NECO)

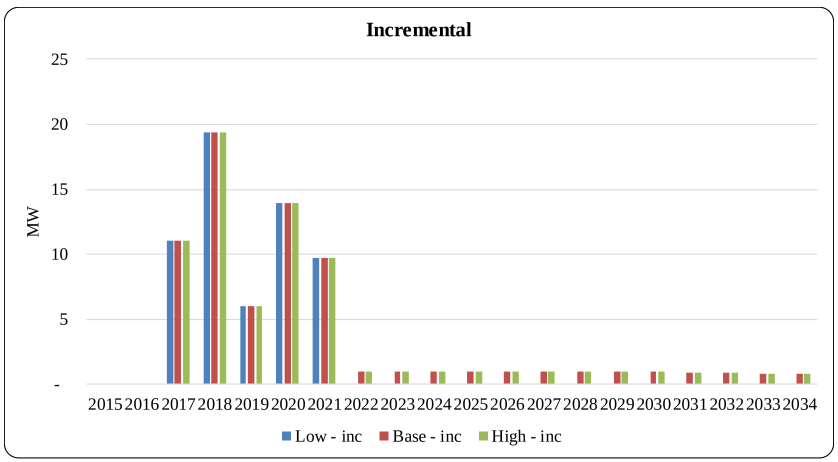
Number of Vehicles						
year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2015	120	404	120	404	120	404
2016	155	559	155	559	155	559
2017	318	877	318	877	318	877
2018	397	1,274	397	1,274	397	1,274
2019	639	1,913	639	1,913	639	1,913
2020	637	2,550	850	2,763	2,268	4,181
2021	637	3,186	1,063	3,827	4,607	8,788
2022	637	3,823	1,276	5,103	7,657	16,445
2023	637	4,459	1,489	6,592	8,934	25,379
2024	637	5,096	1,702	8,294	10,211	35,590
2025	637	5,732	1,915	10,208	11,489	47,079
2026	637	6,369	2,128	12,336	12,766	59,845
2027	637	7,006	2,341	14,677	14,043	73,888
2028	637	7,642	2,553	17,230	15,321	89,209
2029	637	8,279	2,766	19,996	16,598	105,807
2030	637	8,915	2,979	22,976	17,875	123,682
2031	605	9,520	2,873	25,848	17,237	140,919
2032	575	10,095	2,758	28,606	16,548	157,467
2033	546	10,640	2,637	31,244	15,824	173,291
2034	518	11,159	2,513	33,757	15,080	188,371

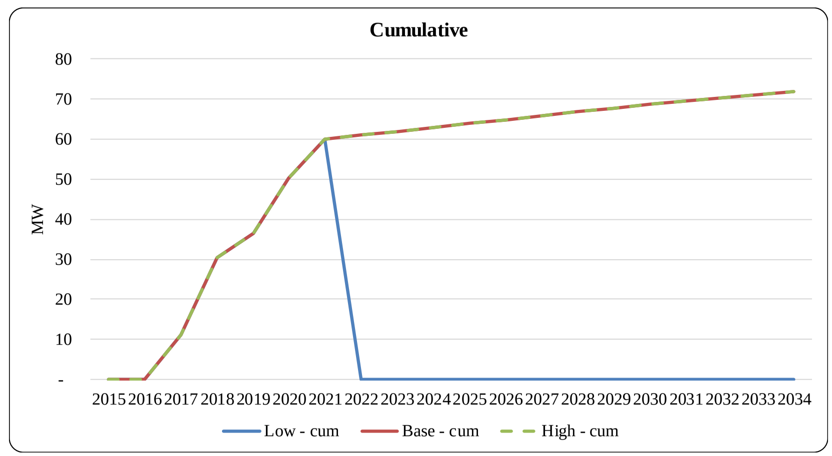




Demand Response (NECO)

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2015	-	-	-	-	-	-
2016	-	-	-	-	-	-
2017	11	11	11.0	11.0	11.0	11.0
2018	19	30	19.4	30.4	19.4	30.4
2019	6	36	6.0	36.4	6.0	36.4
2020	14	50	13.9	50.3	13.9	50.3
2021	10	60	9.7	60.0	9.7	60.0
2022	-	-	1.0	61.0	1.0	61.0
2023	-	-	1.0	61.9	1.0	61.9
2024	-	-	1.0	62.9	1.0	62.9
2025	-	-	1.0	63.9	1.0	63.9
2026	-	-	1.0	64.9	1.0	64.9
2027	-	-	1.0	65.8	1.0	65.8
2028	-	-	1.0	66.8	1.0	66.8
2029	-	-	1.0	67.8	1.0	67.8
2030	-	-	0.9	68.7	0.9	68.7
2031	-	-	0.9	69.6	0.9	69.6
2032	-	-	0.8	70.4	0.8	70.4
2033	-	-	0.8	71.2	0.8	71.2
2034	-	-	0.8	71.9	0.8	71.9





Appendix E: DER Scenarios Development

Base Case:

EE:

- The approved Company goals from the Subject Matter Experts (SMEs) are used for the short-term (i.e. through 2020).
- Post-2020, a declining annual incremental new EE assumption is applied, which is similar to ISO-NE's assumption to reflect the concept of declining returns over time as the market becomes saturated. As a result, the cumulative annual value is still expected to continue to grow but at a slower rate each year. This value is set at 5% less each year.

PV:

- The near-term (i.e. 2019 and 2020) predictions are based on SME expectations for new installations estimated from those in the queue. The projections are compared with the state policy goal of about 40 MW/year (renewable energy growth (REG)). The base case is already doing more than the state target as of now.
- From 2021 to 2023, the same level of incremental growth as 2020 is assumed. This is based on the current queue which has enough to continue at the 2019 assumed rate for several years.
- For the longer term, similar, to other technologies, new installations are assumed to taper off over time due to saturation and increasing costs for the same reductions (at 5% less as in EE above).

EV:

- The near-term trend in annual installations is used to project future installations. This trend is considered to continue through 2030 which coincides with the major milestone year for the 80 * 50 target, a year where many policy targets in the Northeast are established.
- Post-2030 to the end of the forecast horizon, the incremental growth is assumed to taper off. The annual decrease is about 4-5% fewer new vehicles per year than the prior year.

DR (retail):

- For the short term (i.e. until 2021), the approved Company targets from the SMEs in the DR Dept. are used as the projection.
- For the longer term, because the 2021 target level is already at an 'aggressive' level as defined by the consultant report on market potential study (in MA), the projections are only allowed to grow at a minimum rate (i.e. about 10% of the 2021 level).

ES:

- There is currently no energy storage state policy target in RI, thus no assumption for energy storage is made for this planning cycle there. The Company will monitor this and update future forecasts as appropriate. It is noted that there is a small amount of storage being captured in the Company's Demand Response program in RI.

High Case:

EE:

There is no high case at this time because a recent market potential study in MA shows the base is already established at the potential level and a similar study is underway in RI.

PV:

There is no specific new expanded target yet approved in RI, however, there is much discussion in all three states (NY, MA, and RI) on increased renewables by milestone year 2030. Thus, the high case is assumed to be a continuation of the base case levels until milestone year 2030 before saturation and declining growth is assumed. However, a continuation of the base case levels in the 2020's years (vs. an increase in those levels) easily make more than double current state policy target by 2030.

EV:

The base case does not meet the ZEV target by year 2025, which is about 45,000. Thus, the high EV case is a significant increase in annual growth to achieve the ZEV target by 2025. Annual installations are rapidly increased to make the targets. No attempt is made to determine the feasibility of such rapid increases. This trend is continued until the milestone year 2030 where in subsequent years saturation is assumed and an annual decline in new vehicles is assumed. This level is set at about 5% less per year as in the other technologies. It is assumed that significant incentives on the state and federal levels, as well as a transformational change in the industry would be required to enable this scenario.

DR:

No high case is developed because the base case is already at an aggressive level.

Low Case:

EE:

The low case begins the same as in the base cases, however, the tapering off is set at 10% less each year instead of 5%.

PV:

The low case for PV is a tapering off of the current base case in year 2021, the year after the current SME short term projections end, instead of in the year 2023. It also assumes a faster tapering off at 10% less each year.

EV:

The low case is a continuation of the 2019 annual adoption levels. This case assumes continued annual growth, but at a flat level instead of increasing annual levels. In this scenario, the adoption of EVs comes nowhere close to the ZEV targets over the entire 15-year planning horizon.

DR:

The low case for DR is assumed to be a discontinuation of the DR program in the year 2022. Since DR needs to be implemented, dispatched, and paid for continuously unlike other DER programs which once installed persist for many years and still garner savings, the low case is assumed to be an end to the DR due to budget or other circumstances.

Other:

- DERs profiles are applied to allocate the annual projections to peak hours and daily load profiles. Typical Northeastern profiles are applied to all companies and zones.
- It is noted that no attempt to assign probabilities to each of the base, high and low scenarios are made at this time. The base case will be used to establish the forecast base. The highs and lows are provided to inform possible higher and lower cases than the base. Future cycles of the ELF will consider probabilistic approaches.

Appendix F: Power Supply Areas (PSAs)

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

			2019 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2020	2021	2022	2023	2024	'20 to '24	'25 to '29	'30 to '34
RI	Blackstone Valley	RI	100.2%	111.8%	115.1%	(4.2)	(1.1)	(0.2)	(0.2)	(0.2)	(1.2)	(0.3)	(0.5)
RI	Newport	RI	100.2%	111.8%	115.1%	(3.7)	(0.7)	0.1	0.1	0.1	(0.8)	(0.1)	(0.4)
RI	Providence	RI	100.2%	111.8%	115.1%	(4.1)	(1.0)	(0.2)	(0.2)	(0.2)	(1.1)	(0.3)	(0.5)
RI	Western Narraganset	RI	100.2%	111.8%	115.1%	(3.2)	(0.2)	0.6	0.5	0.4	(0.4)	0.2	(0.2)

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

			2019 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2020	2021	2022	2023	2024	'20 to '24	'25 to '29	'30 to '34
RI	Blackstone Valley	RI	100.2%	111.8%	115.1%	(5.3)	(0.6)	0.2	0.2	0.2	(1.1)	0.1	(0.2)
RI	Newport	RI	100.2%	111.8%	115.1%	(4.9)	(0.2)	0.6	0.5	0.5	(0.7)	0.3	(0.1)
RI	Providence	RI	100.2%	111.8%	115.1%	(5.2)	(0.6)	0.3	0.2	0.2	(1.0)	0.1	(0.2)
RI	Western Narraganset	RI	100.2%	111.8%	115.1%	(4.4)	0.2	1.0	0.9	0.8	(0.3)	0.5	0.1

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

			2018/19 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 10/90	for 05/95	2019	2020	2021	2022	2023	'19 to '23	'24 to '28	'29 to '33
RI	Blackstone Valley	RI	96.1%	101.5%	103.0%	(1.6)	(1.8)	(1.7)	(1.5)	(1.3)	(2.2)	(1.0)	(0.4)
RI	Newport	RI	96.1%	101.5%	103.0%	(1.1)	(1.4)	(1.2)	(1.1)	(1.0)	(0.2)	(0.8)	(0.3)
RI	Providence	RI	96.1%	101.5%	103.0%	(1.5)	(1.7)	(1.6)	(1.4)	(1.3)	(0.4)	(1.0)	(0.4)
RI	Western Narraganset	RI	96.1%	101.5%	103.0%	(0.7)	(0.9)	(0.8)	(0.7)	(0.7)	0.3	(0.5)	(0.1)

(1) Zones refer to ISO-NE designations

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

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

Appendix 2

Appendix 2 – NWA Opportunities Summary Table

Project Title	Project Purpose	System Need Detail	NWA Project Details	Affected System Components	Project Origination	Planned Wires Option Work	Planned Start Date	NWA Option Status
Bonnet 42F1 NWA	Load Reduction	The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Feeder 42F1 is projected to be loaded above summer normal ratings by 2024 and lacks useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town.	Load reduction on Bonnet 42 substation, feeder 42F1 to defer or remove the need for feeder line work and reconfiguration.	Bonnet 42F1 feeder	South County East Area Study	Technical requirements currently being reanalyzed.	5/1/2024	Analysis of New NWA (Rescope)
Bristol 51 NWA	MWh Violation and Load Reduction	The Town of Bristol is mostly supplied by (3) 12.47 kV distribution feeders. Loading on the 51F1, 51F2, and 51F3 feeders is predicted to be over 100% of their summer normal ratings and will be overloaded in the next ten years. Either more capacity must be added or load must be reduced in the town.	Load reduction on Bristol 51 substation feeders 51F1, 51F2, 51F3 to defer or remove the need for feeder line work and reconfiguration.	Bristol 51 substation feeders: 51F1, 51F2, 51F3	East Bay Area Study	To resolve the projected MWh exposure and un-served load in the Bristol area, a new feeder is recommended at Bristol substation along with some feeder mainline upgrades and area feeder reconfigurations. The projected in-service date for this new feeder is calendar year 2028.	5/1/2022	Proposal Evaluation
South Kingstown NWA	Load Reduction	The western section of the Town of South Kingston is supplied mostly by (3) 12.47 kV distribution feeders. Two of those feeders (59F3 and 68F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town.	Load reduction on Peacedale 59F3 and Kenyon 69F2 feeders to defer or remove the need for feeder line work and reconfiguration.	Peace Dale 59F3 feeder Kenyon 69F2 feeder	South County East Area Study	Tap existing 68F5 Kenyon Feeder (at Biscuit City Road with new PTR, and extend 20,000' to P12 Tuckertown Road to create a new Normally Open tie point with the 59F3). With this new line extension, load from 68F2 and 59F3 can be transferred to the 68F5, offloading the two overloaded circuits.	5/1/2022	RFP Open

Appendix 3

Appendix 3 – RI NWA BCA Model

CONFIDENTIAL

National Grid requests protective treatment of Appendix 3 in accordance with Rule 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(B).

The Company is providing Appendix 3 as an Excel file because it is too large to legibly produce as a PDF file.

Appendix 4

Appendix 4 – RI NWA BCA Model Technical Reference Manual

National Grid'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 National Grid

September 2020

Table of Contents

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

1. Introduction

National Grid'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.

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

[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 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, National Grid adheres to the RI Test for all NWA investment proposals. National Grid 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	

[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
	Customer empowerment and choice (Customer Level)	O	
	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: 2018 Report" (AESC 2018 Study) prepared by

Synapse Energy Economics for AESC 2018 Study Group, June 1, 2018.[9] This report was sponsored by the electric and gas EE program administrators of National Grid 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 no new EE programs are implemented in New England ("Main Case"), and one in which EE programs are implemented ("With EE" sensitivity case). Note that the "With EE" sensitivity case values are lower than the "Main Case" values by approximately 4-8% on average (i.e., avoided energy cost is 4-5% lower, capacity costs are 8% lower, DRIPE is 5-8% lower).[10] AESC defines their "With EE" sensitivity case as:

> *Future in which energy efficiency measures are installed in 2018 and later years, in direct contrast to the main 2018 AESC case. The purpose of this future is to provide readers of AESC 2018 an avoided cost stream with which to measure avoided costs of measures currently excluded from program administrator energy efficiency plans.*

AESC's "With EE" load projection assumes an annual energy demand reduction of about 20% by 2030. NWAs are site specific solutions that will occur beyond the expected EE reductions. Thus, this analysis will use the "With EE" values for estimating benefits.

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.[11] These generalized values are subject to change.

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[9] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.
[10] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Pages 243 to 250.
[11] "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.

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 2018 Study, Appendix B.[12] The "With EE" values in the AESC Study represent wholesale electric energy commodity costs that are avoided when generators produce less electricity because of non-EE programs so these values are used to evaluate benefits.

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., embedded GHG costs), wholesale risk premium (WRP) that captures market risk factors typically recovered by generators in their pricing,[13] 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 2018 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.

[12] "AESC 2018 Materials." *Avoided Energy Supply Components in New England: 2018 Report, Appendix B*, Synapse Energy Economics, Inc., 2018, www.synapse-energy.com/project/aesc-2018-materials.
[13] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.

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 2018 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,[14] and distribution loss factors representing losses from the ISO delivery point to the end-use customer.

The AESC 2018 Study assumes 8% for distribution system losses[15], which 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)[16], plus the Company's non-PTF transmission loss estimate 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 ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings ElectricEnergyCost$_{SumPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Summer Off-Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{SumOffPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Winter Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{WinPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Winter Off-Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{WinOffPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)

[14] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.
[15] "AESC 2018 Materials." *Avoided Energy Supply Components in New England: 2018 Report, Appendix B*, Synapse Energy Economics, Inc., 2018, www.synapse-energy.com/project/aesc-2018-materials. Detail on ISO Default in Appendix B.
[16] "Tariff Provisions." *National Grid: Bills, Meters & Rates*, National Grid US, www.nationalgridus.com/RI-Business/Rates/Tariff-Provisions.

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 2018, 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 2018, Appendix B, "WRP" AESC default value)
- %D-Losses = 8% (AESC 2018, Appendix B, "DL" ISO-NE default value)
- %Inflation = 2% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")

3.2 RPS and Clean Energy Policy Compliance Benefits

This benefit category captures the value of avoided embedded CO_2 and SO2 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.

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 2018 Study, Appendix B.[17] The "With EE" values in the AESC Study represent wholesale REC costs that are avoided when generators produce less electricity beyond the expected EE energy reductions, so these values are used to evaluate benefits.

Nominal annual benefits are calculated using an average inflation rate to convert AESC's 2018 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,[18] 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-2018) * (1 + WRP) * (1 + %D-Losses)

[17] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.
[18] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- RGGICompliance ($/kWh) = Projected annual values (AESC 2018, Appendix B, "Wholesale REC Costs")
- SOx Embedded ($/kWh) = Projected annual values (AESC 2018, Table 34, Page 92)[19]
- %Inflation = 2.00% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")
- WRP = 8% (AESC 2018, Appendix B, "WRP" AESC default value)
- %D-Losses = 8% (AESC 2018, Appendix B, "DL" 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

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 2018 Study are used in the RI NWA BCA Model. Wholesale Energy DRIPE values in the AESC 2018 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 2018 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

[19] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Page 92, Table 34.

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 2018 results in benefits in 2023). 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 2018 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 $\text{ElectricEnergyCost}_{\text{SumPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Summer Off-Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{SumOffPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Winter Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{WinPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Winter Off-Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{WinOffPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)
- Cross DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * CrossDRIPE $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %T&D-Losses) * (1 + %Inflation)^(year-2018)
- Generation Capacity DRIPE Benefit ($/yr) = ElectricDemandSavings $\text{kW/yr}_{\text{SumPk}}$ * WholesaleCapDRIPE $/kW-yr * TechnologyCoincidence * (1 + WRP) * (1 + %D-Losses) * (1 + %Inflation)^(year-2018)

Where:

- ElectricEnegySavings (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 ($/kWh) = Projected annual values (AESC 2018, Appendix B, "Intrastate - Wholesale Energy DRIPE")
- CrossDRIPE ($/kWh) = Projected annual values (AESC 2018, Appendix B, "Intrastate – Wholesale Cross DRIPE")
- RetailCapDRIPE ($/kW-yr) = Projected annual values (AESC 2018, Appendix B, "Intrastate – Retail 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 2018, Appendix B, "WRP" AESC default value)
- %T&DLosses = 1.6% (AESC 2018, Appendix B, "PTF Loss" AESC default value) + 8% (AESC 2018, Appendix B, "DL" ISO-NE default value)
- %Inflation = 2% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")

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.[20] 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 2018 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

[20] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Page 203.

convert AESC's 2018 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 ($/yr) = ElectricDemandSavings kW/yr$_{SumPk}$* CapCost $/kW-yr * %Summer Coincidence * TechnologyCoincidence * (1+WRP) * (1+%D-Losses) * (1 + %Inflation)^(year-2018)

Where:

- ElectricDemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- WholesaleCapCost ($/kW-yr) = Projected annual values (AESC 2018, Appendix B, "Wholesale Cost of 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 2018, Appendix B, "WRP" AESC default value)
- %D-Losses = 8% (AESC 2018, Appendix B, "DL" ISO-NE default value)
- %Inflation = 2% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")

The AESC 2018 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 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 taken into account 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 2018 Study calculates an avoided cost for PTF of $94/kW-year in 2018 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 2018 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 + T&DLosses) * (1 + %Inflation)^(year-2018) * TransmissionsCoincidence

Where:

- DemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- TransCapCost ($/kW-yr) = $94/kW-year (AESC 2018, Appendix B, "T&D Cost")
- %Summer Coincidence = % of NWA peak capacity at ISO peak
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- %T&DLosses = 1.6% (AESC 2018, Appendix B, "PTF Losses") + 8% (AESC 2018, Appendix B, "ISO default")
- %Inflation = 2% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")
- 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.[21]

According to the AESC 2018 Study, the cost of GHG emissions reductions can be determined based on estimating either carbon damage costs or marginal abatement costs. A 2014 meta-analysis of the social cost of carbon based on damage costs found that the social cost of carbon should be at least $125 per metric ton ($113 per short ton) of CO_2,[22] but 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.[23]

The AESC 2018 Study developed two 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.[24] 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 $100 per short ton of CO_2 equivalent and is identical to the prior AESC 2015 Study[25] value used in the 2018 and 2019 study years. 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.

On October 24, 2018 an amendment to the AESC 2018 Study was issued that corrected assumptions related to the calculation of offshore wind costs. Based on this corrected projection of the future incremental cost of offshore wind energy at $31/MWh and a natural gas generator emissions rate of 0.46 short tons CO_2 per MWh, the AESC 2018 Study amendment estimates a New England specific abatement cost of $68 per short ton of CO_2 equivalent. Note that the AESC 2018 Study estimates the 15-year levelized cost of offshore wind prices will be approximately $80/MWh. After subtracting the cost of energy within the 2018 AESC construct (estimated to be $49/MWh, based on an annual 15-year levelized cost for the West/Central Massachusetts (WCMA) region), the future incremental cost of offshore wind energy would be $31/MWh.

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[21] 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.

[22] van den Bergh, J., Botzen, W. A lower bound to the social cost of CO_2 emissions. *Nature Clim Change* 4, 253–258 (2014). https://doi.org/10.1038/nclimate2135. Page 256.

[23] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Pages 140 to 142.

[24] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. See *Chapter 4. Common Electric Assumptions* for a discussion of how these costs are modeled.

[25] "Avoided Energy Supply Components in New England: 2015 Report." *Massachusetts Energy Efficiency Advisory Council: Special & Cross-Sector Studies*, Synapse Energy Economics, Inc., 3 Apr. 2015, http://ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report.pdf.

However, the emissions rate used by AESC appears to be based on the U.S. average "uncontrolled emissions factor" for natural gas generators (i.e., 0.46 short tons of CO_2 per MWh),[26] while the most recent electric generator air emissions report from ISO-NE states that the marginal emissions factor for ISO-NE generators is 0.33 short tons of CO_2 per MWh (655 lbs CO_2/MWh).[27] The Company believes this lower ISO-NE emission factor is more appropriate to use, and notes that the emissions factor could be even lower in the future. Therefore, the New England specific abatement cost is $92 per short ton of CO_2 equivalent based on the 2018 ISO-NE emissions factor of 0.33 short tons of CO_2 per MWh.

Given the uncertainties in both the higher damage cost estimate ($113 per short ton of CO_2) and the lower New England specific abatement cost estimate ($92 per short ton of CO_2) based on future incremental costs of offshore wind energy and future marginal emissions factors, the Company proposes to apply the global marginal carbon abatement cost of $100 per short ton in the RI NWA BCA Model, which is in between the other two estimates. The costs of compliance with the RGGI are already included or "embedded" in the projected electric energy market prices. Therefore, the difference between the $100 per short ton societal cost and the RGGI compliance costs already embedded in the projected energy market prices represents the value of carbon emissions not included in the avoided energy costs.

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 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 GHG Reduction Benefit ($/yr) = ElectricEnergySavings kWh/yr * GHGEmissionsRate ton/kWh *(NonEmbeddedGHGValue - EmbeddedGHGValue) * TechnologyCoincidence * EfficiencyLoss * (1 + T&D$Losses_{Ave}$) * (1 + %Inflation)^(year-2018)

Where:

- ElectricEnegySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- GHGEmissionsRate (ton/kWh) = 0.33-ton CO_2/MWh * 1/1000 MWh/kWh (ISO-NE 2020,[28] Table 5-3, 2018 Time-Weighted Locational Marginal Unit (LMU) Marginal Emissions Rates-All LMUs, "Annual Average (All Hours)")
- NonEmbeddedGHGValue ($/ton) = $100/ton (AESC 2018, Table 151, "AESC 2018 Non-Embedded CO_2 Cost")

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[26] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Pages 142-144.
[27] "2018 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., May 2020, www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Page 30, Table 5-3.
[28] "2018 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., May 2020, www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Page 30, Table 5-3.

- EmbeddedGHGValue ($/ton) = Projected annual values (AESC 2018, Table 151, "Embedded Cost of RGGI")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %T&DLosses = 1.6% (AESC 2018, Appendix B, "PTF Losses") + 8% (AESC 2018, Appendix B, "ISO default")
- %Inflation = 2% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")

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.[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 NOx costs from "electricity generating units".[30] 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.[31,32] Using the average of the results from the two studies, the RI NWA BCA Model estimates the non-embedded NOx emissions cost to be $10,100 per ton of NOx in 2020 (2015 dollars) increasing to $11,600 per ton of NOx in 2030 (2015 dollars). These translate into $0.90 per MWh in 2020 and $1.04 per MWh in 2030 (2018 dollars) using the ISO-NE 2018 marginal NOx emissions factor of 0.17 lb NOx/MWh.[33] Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 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.

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[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] "2018 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., May 2020, www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Page 30, Table 5-3.

The dollar value of annual benefits is therefore calculated as:

- Non-Embedded NOx Reduction Benefit ($/yr) = ElectricEnergySavings kWh/yr * NOxEmissionsRate ton/kWh * NonEmeddedNOxValue $/ton * TechnologyCoincidence * EfficiencyLoss * (1 + T&DLosses$_{Ave}$) * (1 + %Inflation)^(year-2018)

Where:

- ElectricEnegySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- NOxEmissionsRate (ton/kWh) = 0.17 lb NOx/MWh * 1/1,000 MWh/kWh ÷ 2,000 lb/ton (ISO-NE 2020,[34] Table 5-3, 2018 Time-Weighted LMU Marginal Emissions Rates-All LMUs, NOx “Annual Average (All Hours)”)
- NonEmbeddedNOxValue ($/ton) = $10,100-$11,60012,211/ton (US EPA 2019, Tables 5-10, average of NOx from “Electricity Generation Units”, inflated to 2018 dollars)[35,36]
- TechnologyCoincidence = Coincidence Factor based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %T&DLosses = 1.6% (AESC 2018, Appendix B, “PTF Losses”) + 8% (AESC 2018, Appendix B, “ISO default”)
- %Inflation = 2% (AESC 2018, Table 134, “GDP Price Index and Inflation Rate”)

Note that the AESC 2018 Study also estimates avoided NOx emissions costs utilizing a continental U.S. average, non-location specific, non-embedded NOx emission wholesale cost of $11,935 per ton of NOx[37] or $1.65 per MWh assuming a NOx emissions factor of 0.03 lb NOx/MMBtu and Heat Rate of 9,220 Btu/kWh (0.28 lb NOx/MWh) based on a generic unit addition of a natural gas-fired combustion turbine in New England.[38] While the wholesale cost of NOx is similar to the cost used in the RI NWA BCA Model, the NOx emission factor used in the RI NWA BCA Model is lower than the AESC Study, because the RI NWA BCA Model uses the most recent ISO-NE published marginal emissions factors.

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34 “2018 ISO New England Electric Generator Air Emissions Report.” *ISO New England*, ISO New England Inc., May 2020, www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Page 30, Table 5-3.

35 The AESC Study’s annual electric energy values include no embedded NOx reduction values, due primarily to New England states being exempt from the Cross-State Air Pollution Rule (CSAPR) program.

36 “Cross-State Air Pollution Rule (CSAPR).” *US EPA*, United States Environmental Protection Agency, 5 May 2020, www.epa.gov/csapr.

37 “Avoided Energy Supply Components in New England: 2018 Report.” *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Page 144 reports a cost of $31,000 per ton of nitrogen (2018 dollars), which translates into a cost of $11,935 per ton of NOx based on the other assumptions provided.

38 “Avoided Energy Supply Components in New England: 2018 Report.” *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Page 81, Table 30.

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.[39]

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".[40] 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.[41,42] 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 2018 marginal SO_2 emissions factor of 0.11 lb SO_2/MWh.[43] 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 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 $/ton) * TechnologyCoincidence * EfficiencyLoss (1 + T&DLosses$_{Ave}$) * (1 + %Inflation)^(year-2018)

[39] "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.
[40] "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.
[41] 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.
[42] 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.
[43] "2018 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., May 2020, www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Page 30, Table 5-3.

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- SO_2EmissionsRate (ton/kWh) = 0.11 lb SO_2/MWh * 1/1,000 MWh/kWh ÷ 2,000 lb/ton (ISO-NE 2020,[44] Table 5-3, 2018 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) = $0.52/ton (AESC 2018, Table 34, SO_2 "2018$")[45]
- TechnologyCoincidence = Coincidence Factor based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %T&DLosses = 1.6% (AESC 2018, Appendix B, "PTF Losses") + 8% (AESC 2018, Appendix B, "ISO default")
- %Inflation = 2% (AESC 2018, Table 134, "GDP Price Index and Inflation Rate")

Note that the AESC 2018 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.[46]

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.

National Grid 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 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

[44] "2018 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., May 2020, www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf. Pages 29 and 30.

[45] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Page 92, Table 34.

[46] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Page 56.

schedules are typically based on an annual, semi-annual, or monthly cadence. 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%)[47] 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.

[47] "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 2018 Materials Source Reference

Please refer to the following citation for the Appendix B data tables of the AESC 2018 Study materials.

> "AESC 2018 Materials." *Avoided Energy Supply Components in New England: 2018 Report*, Synapse Energy Economics, Inc., 2018, www.synapse-energy.com/project/aesc-2018-materials.

Appendix 2: Table of Terms

Term	Definition
AESC	Avoided Energy Supply Components
AESC 2018 Study	Avoided Energy Supply Components in New England: 2018 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

Term	Definition
NOx	Nitrogen oxides (NO, NO_2)
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