

SYSTEM RELIABILITY PROCUREMENT
2021-2023 THREE-YEAR PLAN

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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

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. _____
2021-2023 System Reliability Procurement Three-Year Plan

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
NO _x	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 Grid¹ 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 Public Utilities Commission (PUC)² 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.

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

² "RIPUC." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island, www.ripuc.ri.gov/.

SRP Section	SRP Initiative/Proposal	Requested Ruling
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.
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.

SRP Section	SRP Commitment
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.
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)³ goals, align with Docket 4600⁴ principles, are coordinated with the Company's other programs and filings, and adhere to Least-Cost Procurement (LCP) law.

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³ "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.

⁴ "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).⁵⁶

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 (together, 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.

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⁵ 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).

⁶ "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 § 39-1-27.7,⁷ the basis for which is the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006⁸ (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).⁹ 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.¹⁰

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;*

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

⁸ “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>.

⁹ “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>.

¹¹ “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>.

- (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.¹¹ 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 (CO₂) mitigation, as imposed by the Regional Greenhouse Gas

¹¹ “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>.

Initiative (RGGI)¹², and other utility system costs are accounted for in the RI NWA BCA Model 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	

¹² “State Statutes & Regulations - Rhode Island.” *The Regional Greenhouse Gas Initiative*, RGGI, Inc., www.rggi.org/program-overview-and-design/state-regulations.

RI Test Category	Docket 4600 Category	SRP Program	Notes
Non-Energy Impacts	Distribution Delivery Costs (Power System Level)	O	(2)
	Distribution system safety loss/gain (Power System Level)	O	
	Customer empowerment and choice (Customer Level)	O	
	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 (NO _x) 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	
<p>Notes</p> <p>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.</p> <p>(1) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e. NWAs or NPAs).</p> <p>(2) Currently do not have data to claim benefits for a targeted need case.</p> <p>(3) Sensitivity analysis is currently under development. This benefit is negligible unless sensitivity analysis determines otherwise.</p>			

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 addition 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 Test¹³, as detailed in Section 3.1 and 3.2 and through the evaluation process as detailed in Section 7.4.

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¹³ “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 20-01¹⁴ that mandates “to meet one hundred percent (100%) of the state’s electricity demand with renewable energy resources by 2030”, Executive Order 19-06¹⁵ 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 2014¹⁶.

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¹⁴ R.I. Executive Order No. 20-01 (Jan. 17, 2020), <https://governor.ri.gov/documents/orders/Executive-Order-20-01.pdf>.

¹⁵ R.I. Executive Order No. 19-06 (July 8, 2019), <https://governor.ri.gov/documents/orders/Executive%20Order%2019-06.pdf>.

¹⁶ “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 4770.¹⁷ Only additional, incremental costs for plan implementation of proposed projects and programs are included in SRP funding requests.

¹⁷ "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.

$$\text{Company Share} = \text{Net Benefits} \times 20\%$$

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

$$\text{Customer Share} = \text{Net Benefits} \times 80\%$$

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. ¹⁸ 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 propose to 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

¹⁸ 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. Scoping

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.¹⁹

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. Initial System Assessment

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.

¹⁹ 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. Select Recommended Plan

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

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

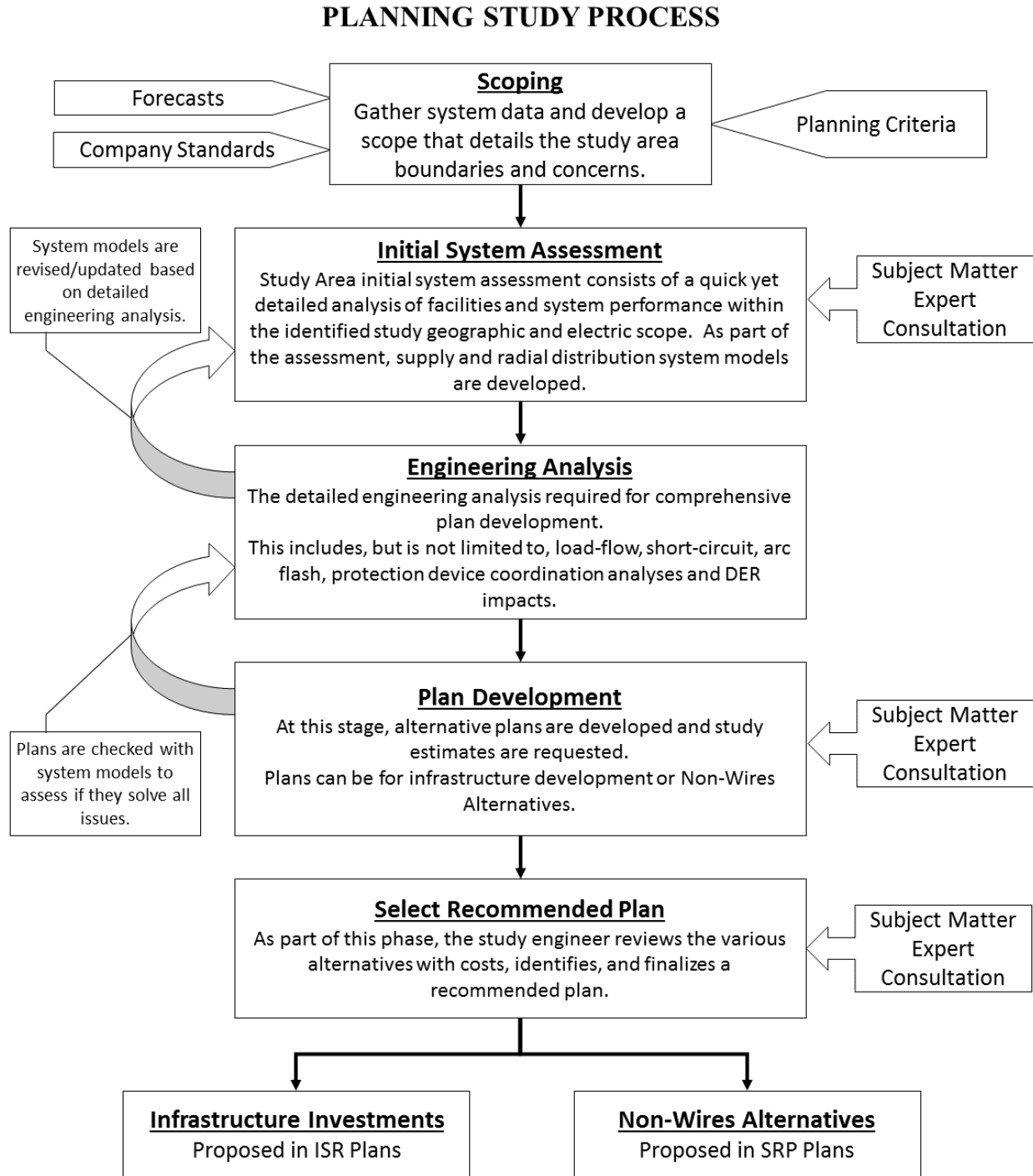
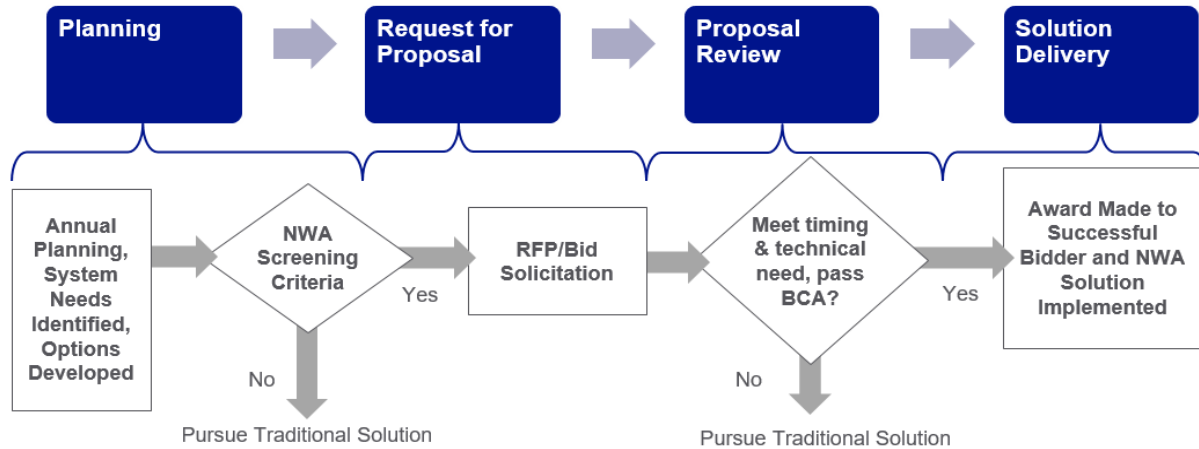


Figure 2: Overview of National Grid’s NWA Procurement Process



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.

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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.

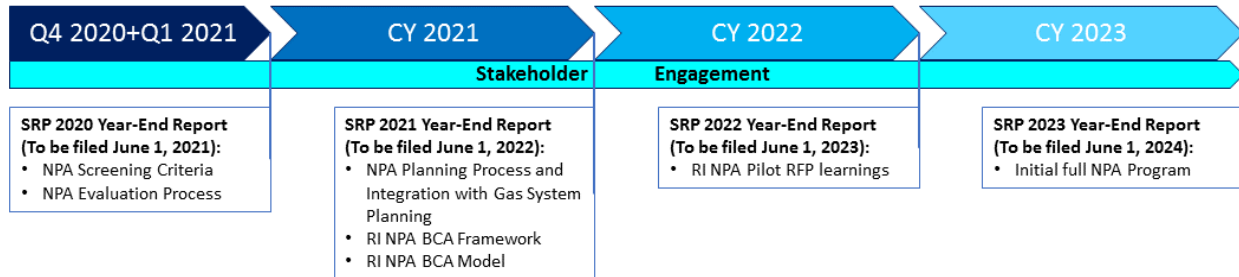
An NPA can include any action, strategy, program, or technology that meets this definition and these requirements. The Company is currently engaged in ongoing discussions with stakeholders about potential solution types in consideration of NPA solutions, proposals, and investment decisions.

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



Stakeholder Engagement

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.

NPA Screening Criteria

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.

NPA Planning Process and Integration with Gas System Planning

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

DR²⁰, 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.

²⁰ “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.

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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.²¹

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.

²¹ 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.²²

The NWA tab that contains a link to National Grid’s NWA Website²³, 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.

²² “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/>.

²³ “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.²⁴
- 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

²⁴ "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)²⁵, the Infrastructure, Safety and Reliability (ISR) Plans^{26,27}, the Renewable Energy Growth (REG) Program²⁸, 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 Report²⁹ 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.

²⁵ "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.

²⁶ "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.

²⁷ "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.

²⁸ "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.

²⁹ "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 2024/25.³⁰

- 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

³⁰ "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](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.

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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.

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY
D/B/A NATIONAL GRID

By its Attorney,
Andrew S. Marcaccio

Date

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Appendices

- Appendix 1 Rhode Island Company Electric Service Projected Load Growth**
- Appendix 2 NWA Opportunities Summary Table**
- Appendix 3 RI NWA BCA Model**
- Appendix 4 RI NWA BCA Model TRM**

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Appendix 1 – Rhode Island Company Electric Service Projected Load Growth

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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%.

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Rhode Island Projected Load Growth Rates

State	County	Town	Annual Growth Rates (%)										5-year Average (%)	10-year Average (%)
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2020 to 2024	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

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

<u>Version</u>	<u>Date</u>	<u>Changes</u>
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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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 1¹ shows the Company's service territory in the U.S.

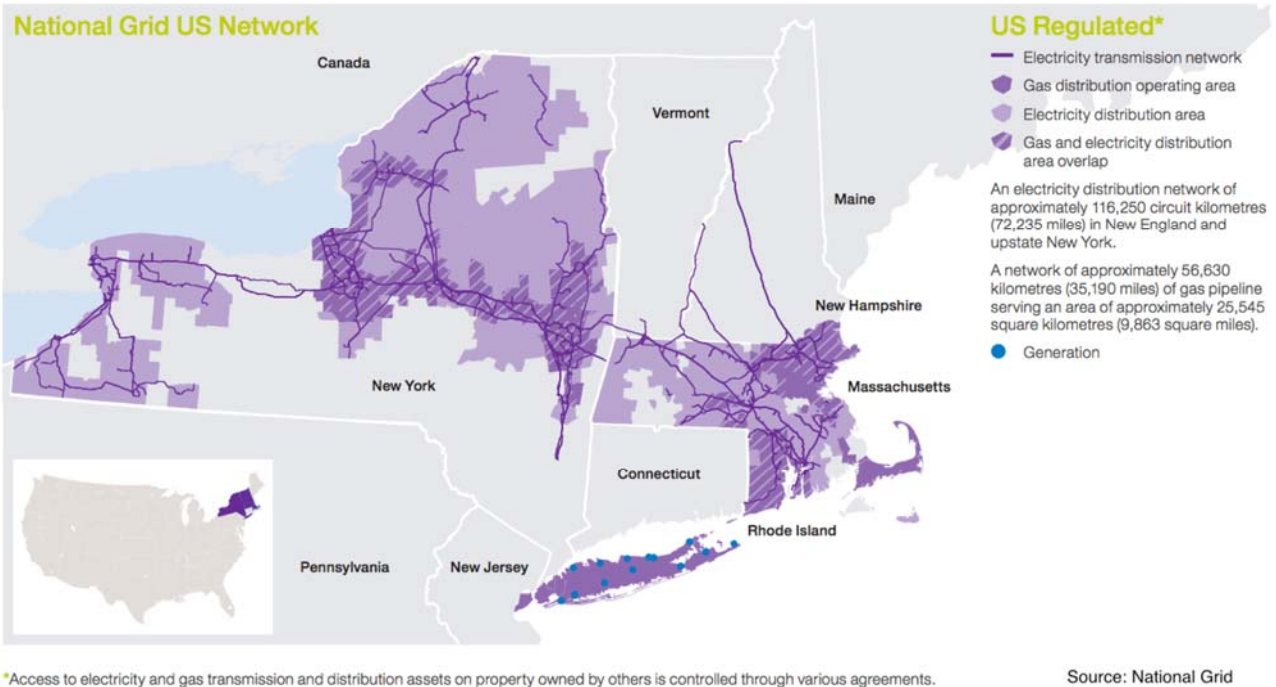


Figure 1: National Grid U.S. Service Territory

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's² 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 warmer³. 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.

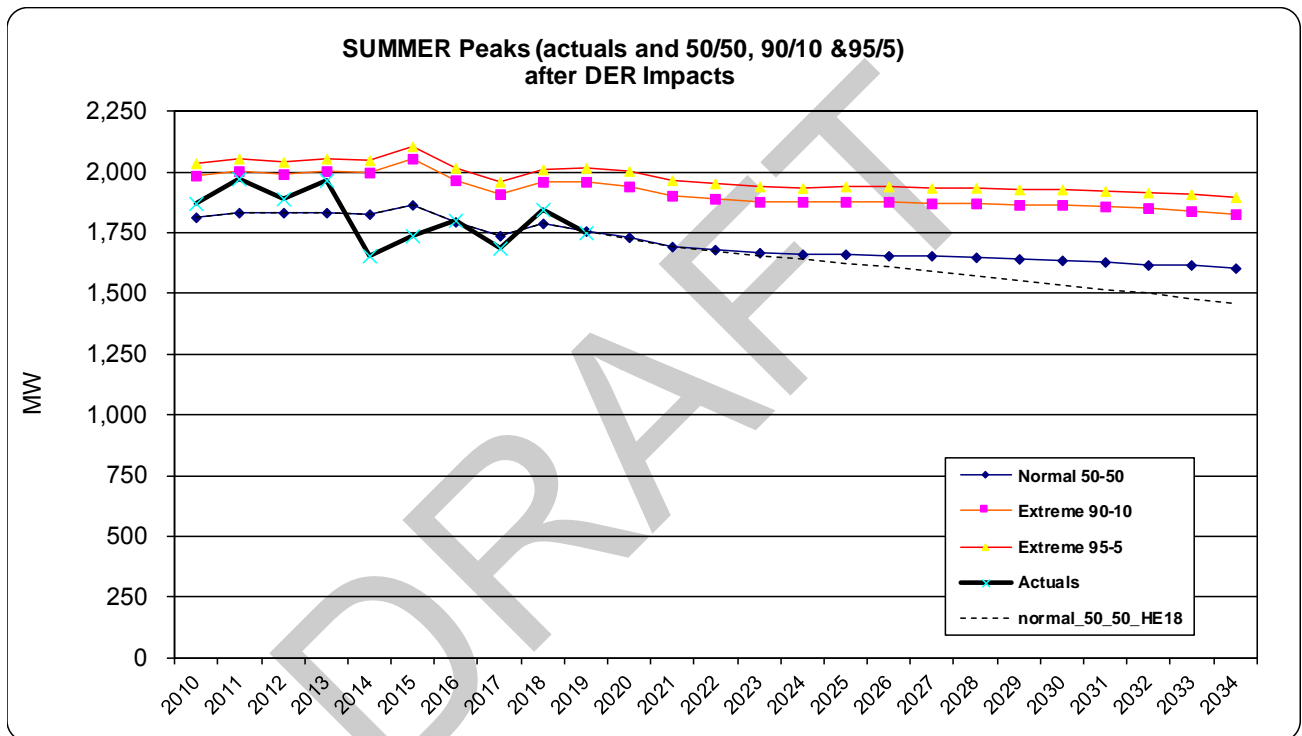


Figure 2: Historical (actual & weather-adjusted) and Projected Summer Peaks

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.

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.

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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 $(0.55 * \text{dry bulb temperature}) + (0.20 \text{ dew point}) + 17.5$. 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).

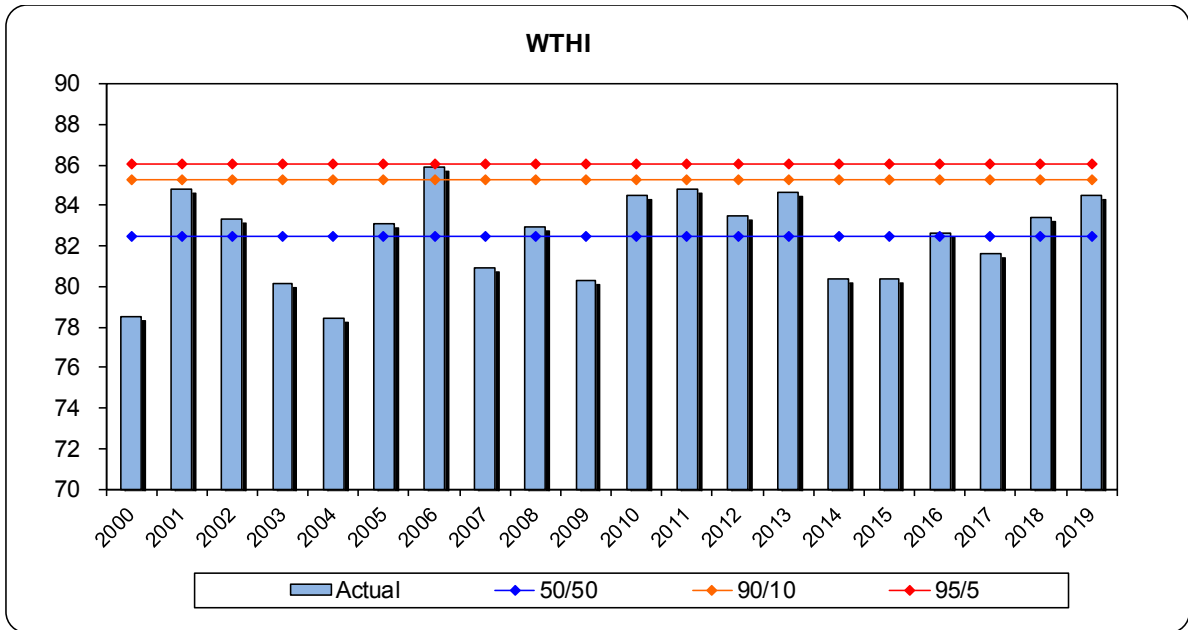


Figure 3: Actual, weather-normal and extreme WTHI

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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 negative 0.6% per year.

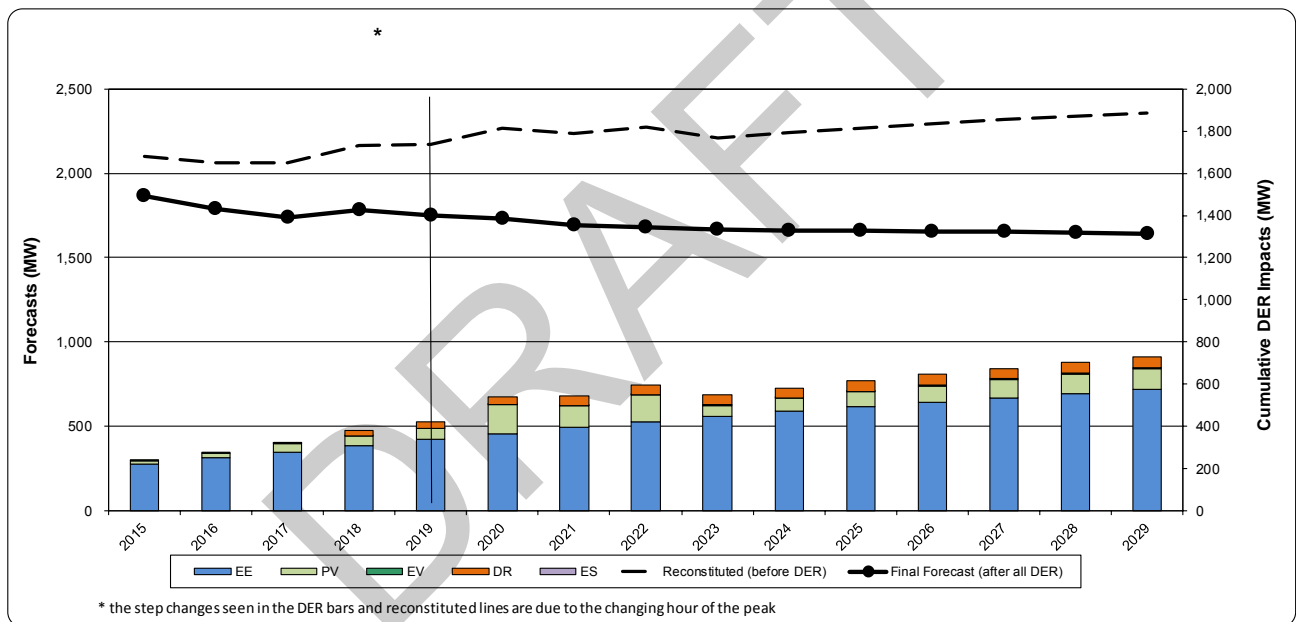


Figure 4: Annual impact of DERs

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 shifts⁷. 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 - PV⁸

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.

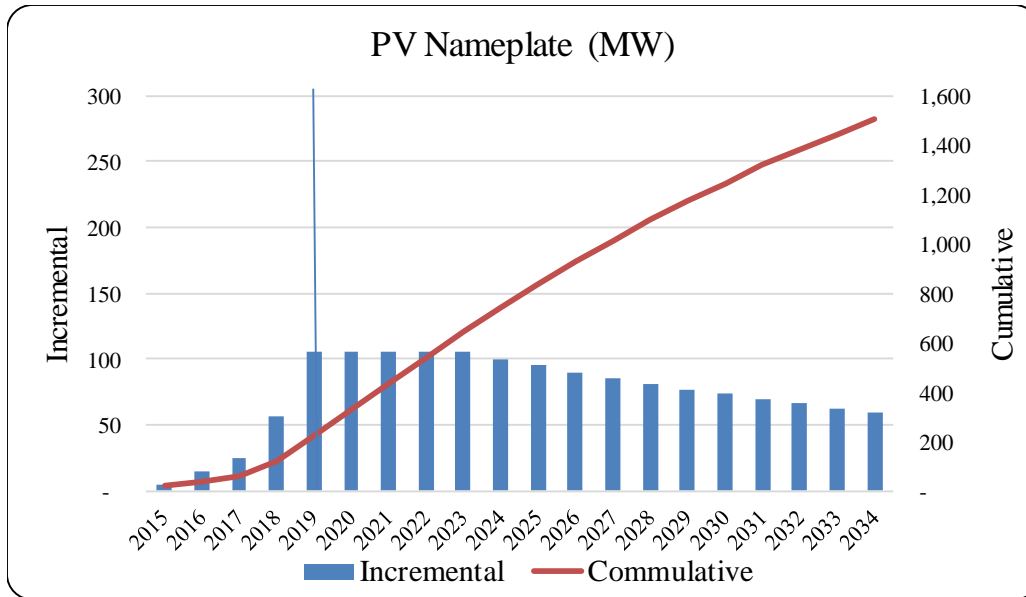


Figure 5: Solar-PV connected nameplate (AC) MW by year

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.

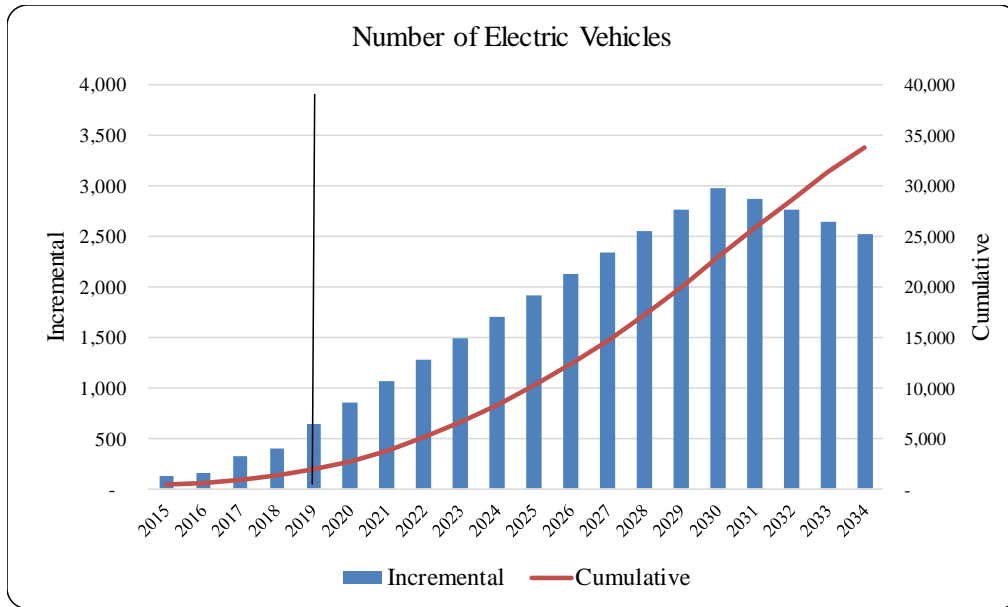


Figure 6: Number of Incremental and Cumulative EVs

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.

Demand Response (DR)

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.

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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.

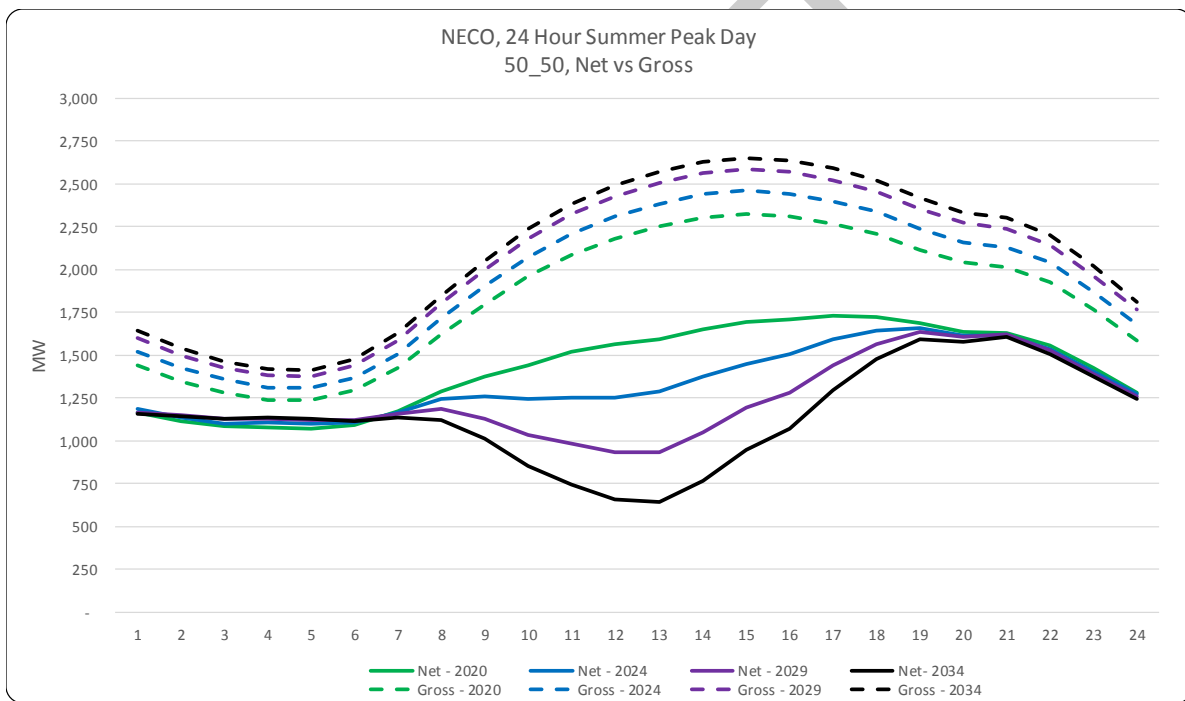


Figure 7: Peak Summer day hourly load, pre and post DERs

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.

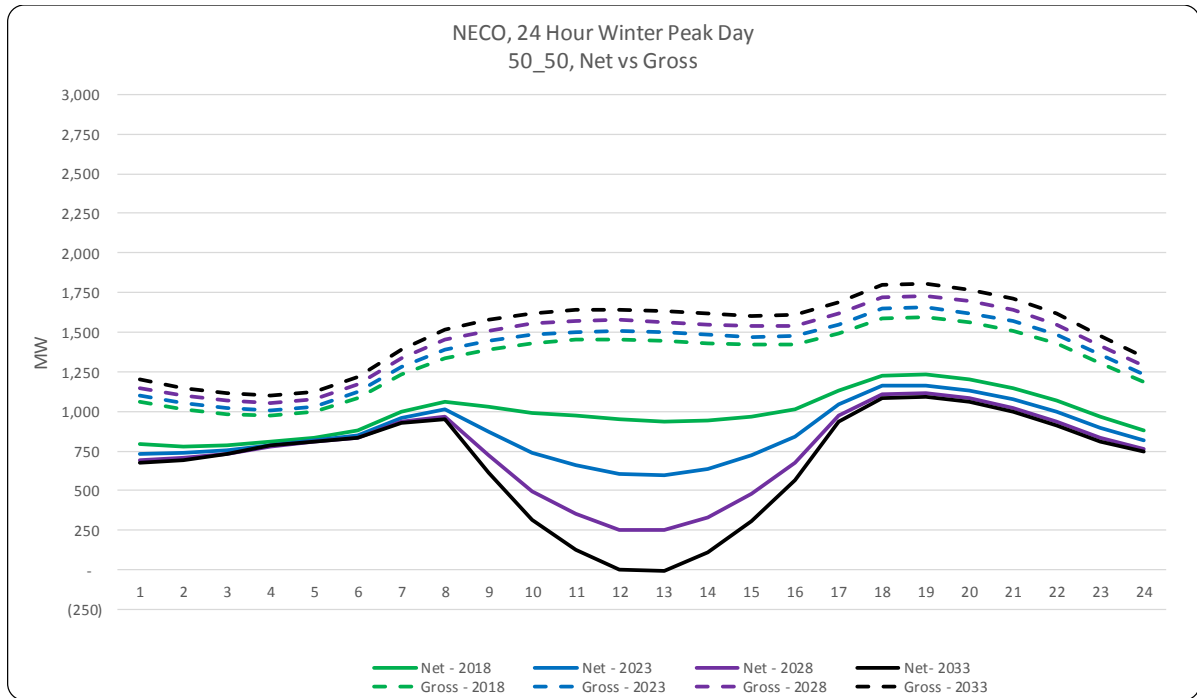


Figure 8: Peak Winter day hourly load, pre and post DERs

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 scenarios¹⁰.

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.

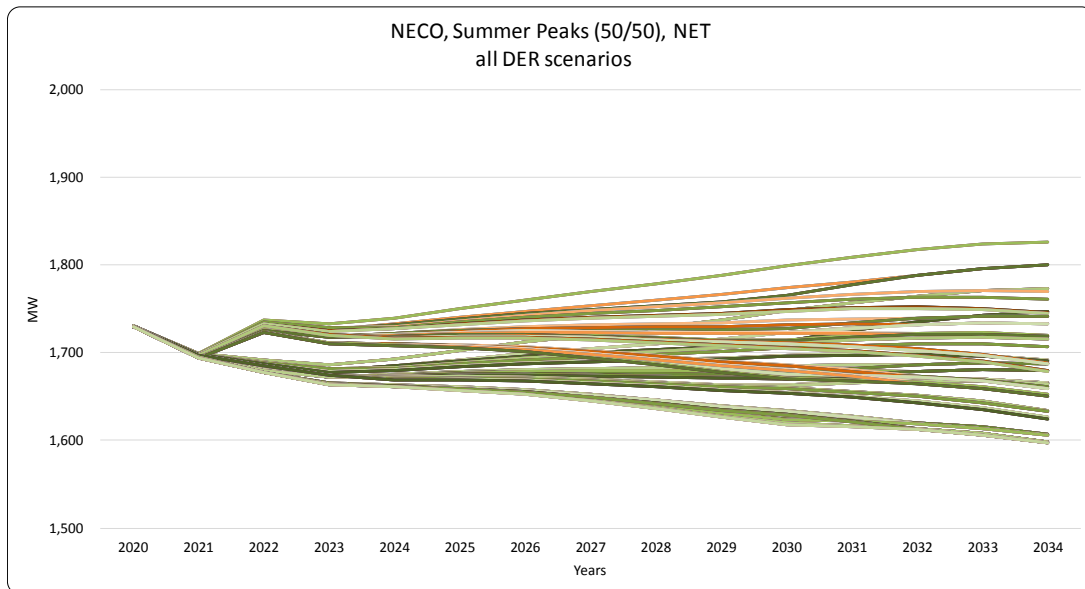


Figure 9: Summer Peaks (50/50), NET, all DER scenarios

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.

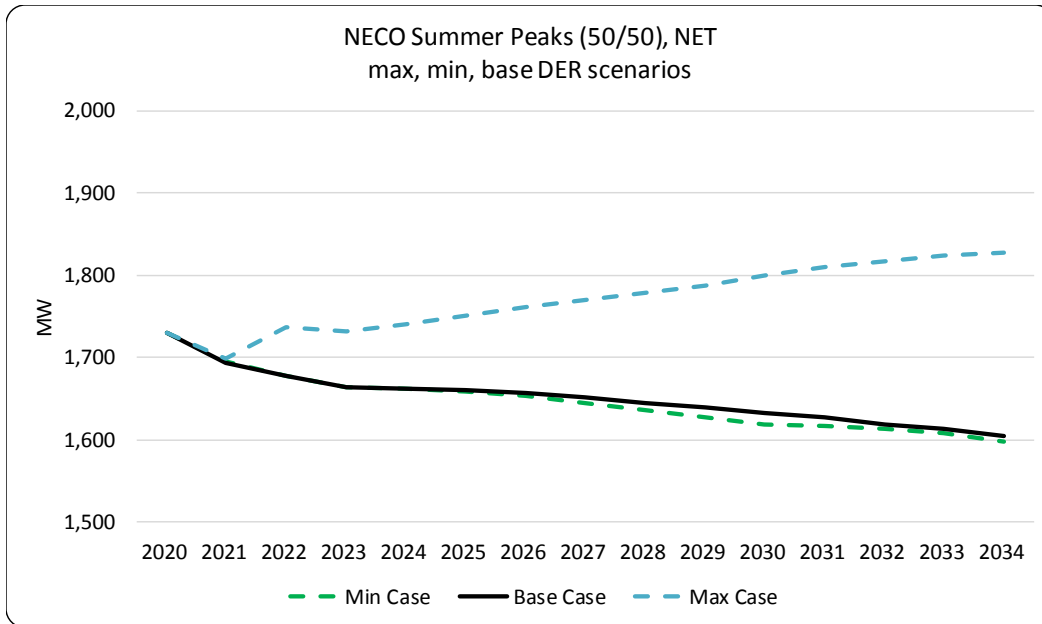


Figure 10: Annual Summer Peaks for Base Case, Maximum and Minimum Cases

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.

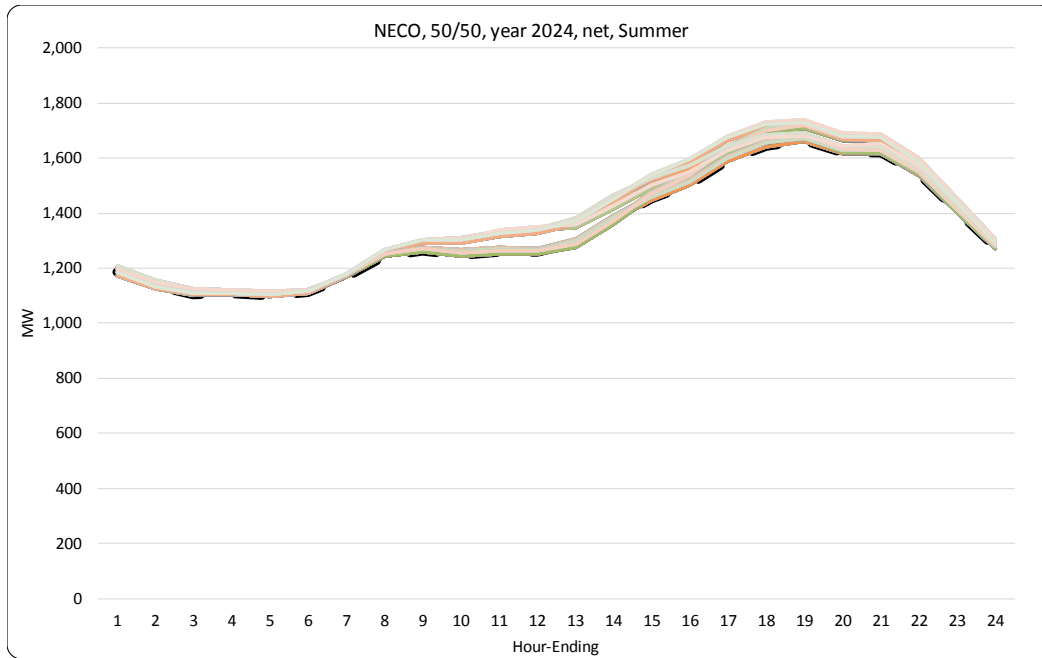


Figure 11: 50/50 case, net summer peak, w/range of DER scenarios, year 2024

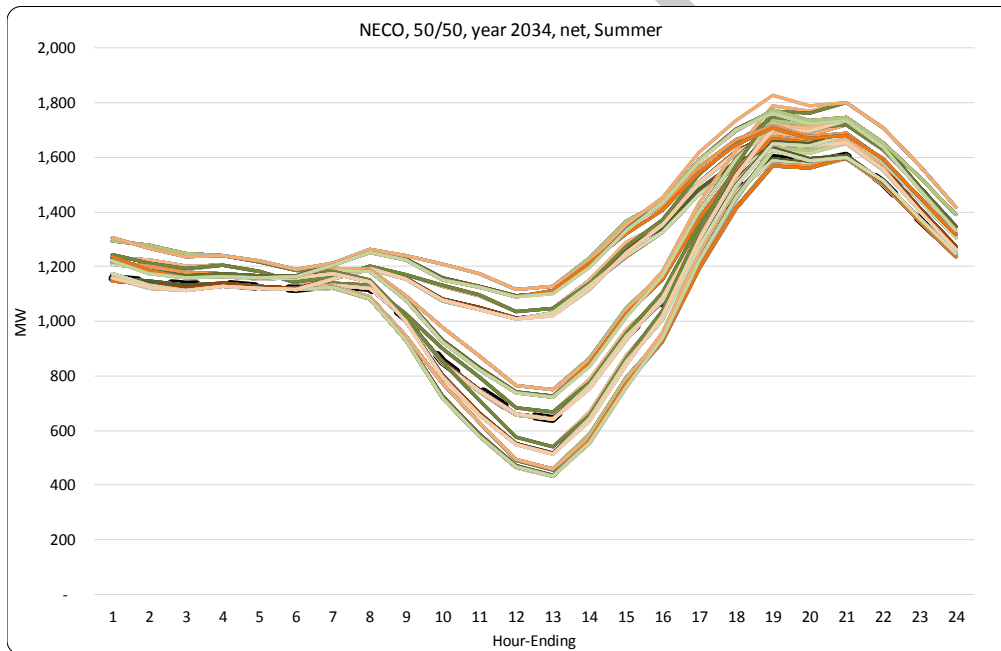


Figure 12: 50/50 case, net summer peak, w/range of DER scenarios, year 2034

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.

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Appendix A: Forecast Details

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NECO
SUMMER Peaks **AFTER DER Impacts ***

YEAR	Actuals		Normal 50-50		Extreme 90-10		Extreme 95-5		WTHI
	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	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%	WTHI
Avg. last 10 yrs			-0.4%	-0.2%	-0.2%	NORMAL 82.4
Avg. last 5 yrs			-0.8%	-0.4%	-0.3%	EXTREME 90/ 10 85.3
BASE 2019						EXTREME 95/ 5 86.1
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%	

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

NECO		SUMMER 50/50 Peaks (MW) (before & after DERs)																		
Calendar Year	SYSTEM PEAK							DER IMPACTS						% of reconstituted peaks						
	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		Normal 50-50		Extreme 10-90		Extreme 05-95		HDD_wtd
	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	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%	-

Avg. last 15 yrs	-0.7%	-0.3%	-0.2%	HDD_wtd NORMAL 43.8 EXTREME 90/ 10 54.7 EXTREME 95/ 5 57.8
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%	

* 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

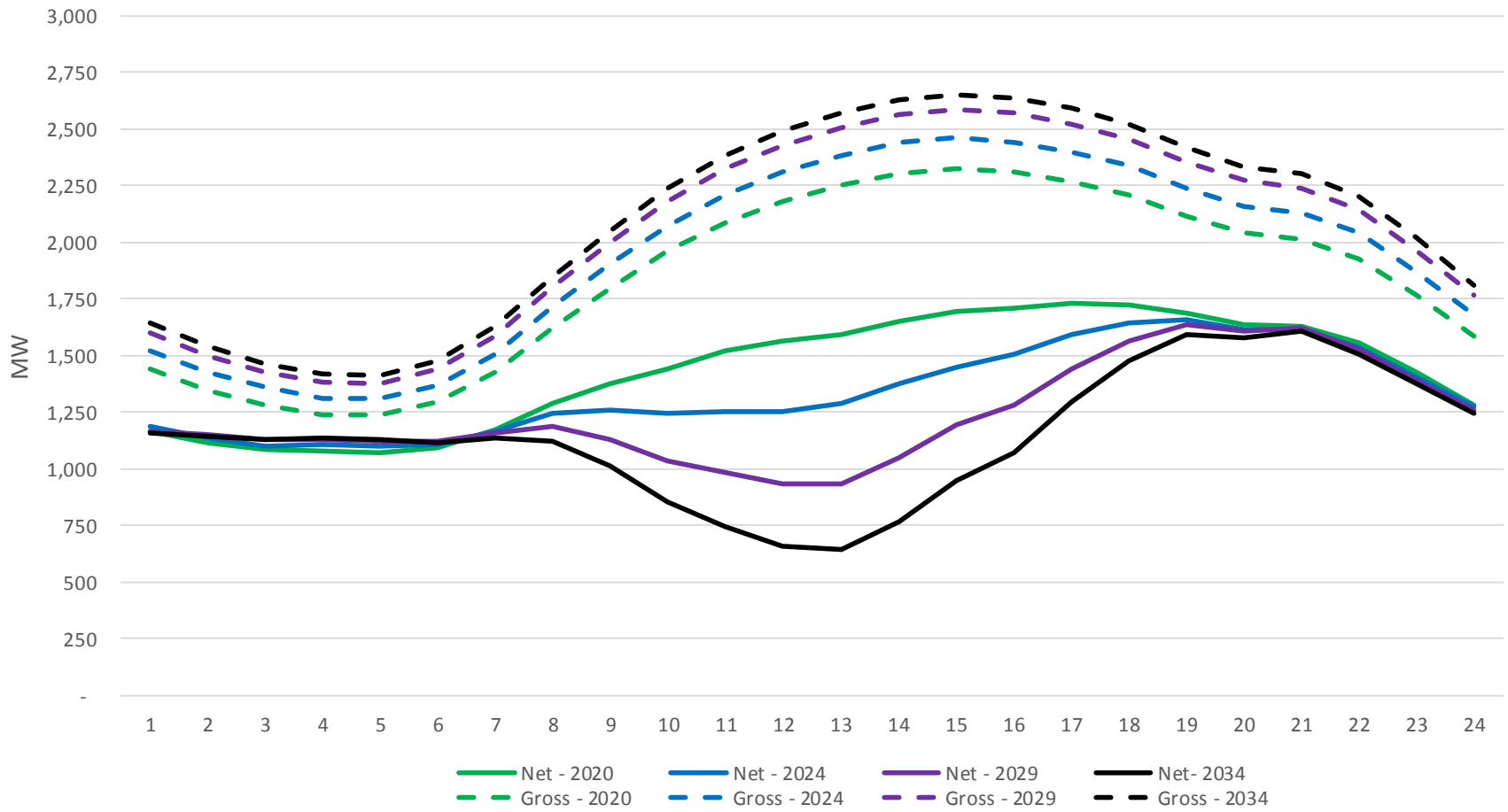
Winter Peaks

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

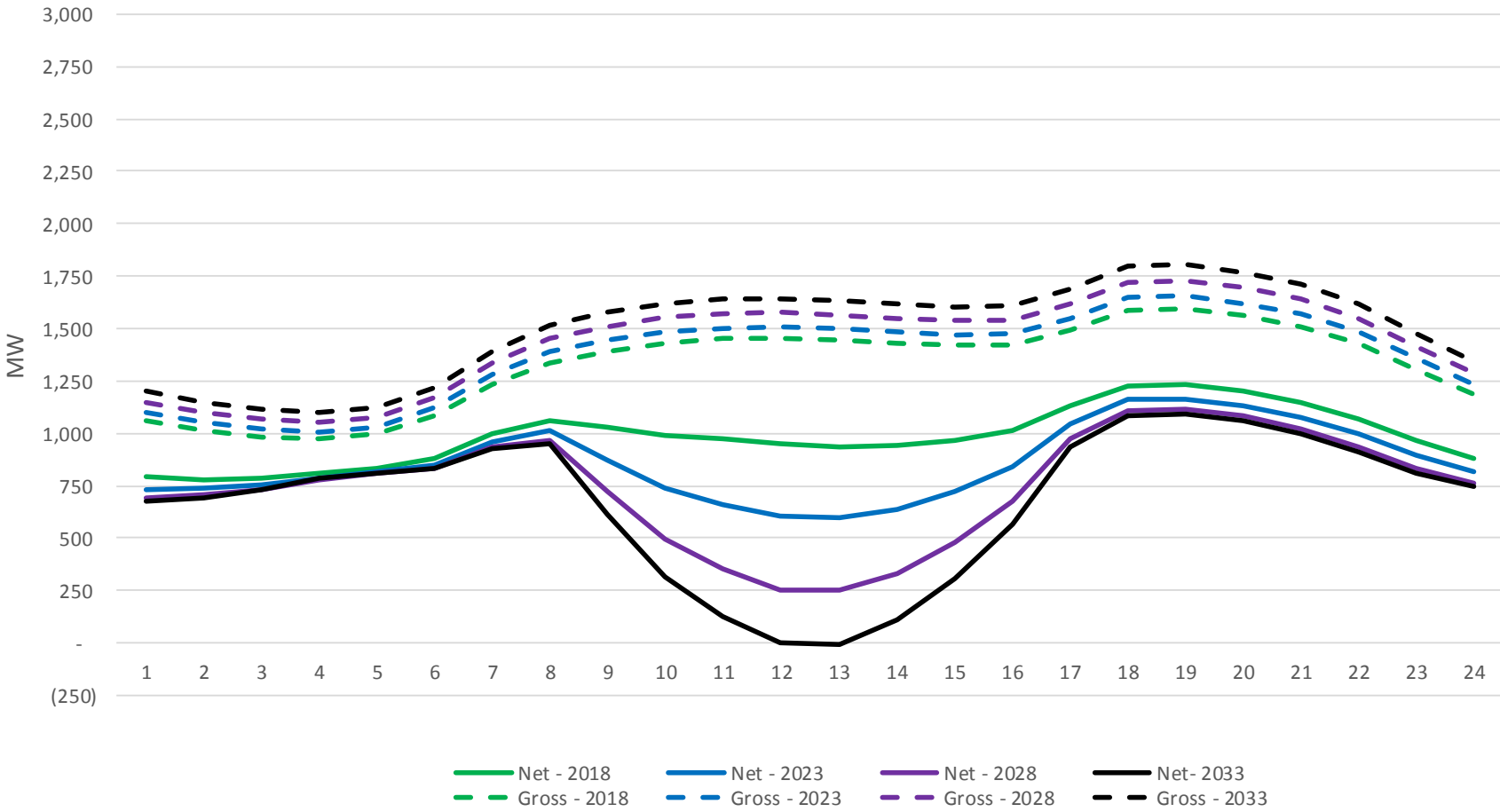
Appendix C: Load Shapes for Typical Day Types
(for Base Case)

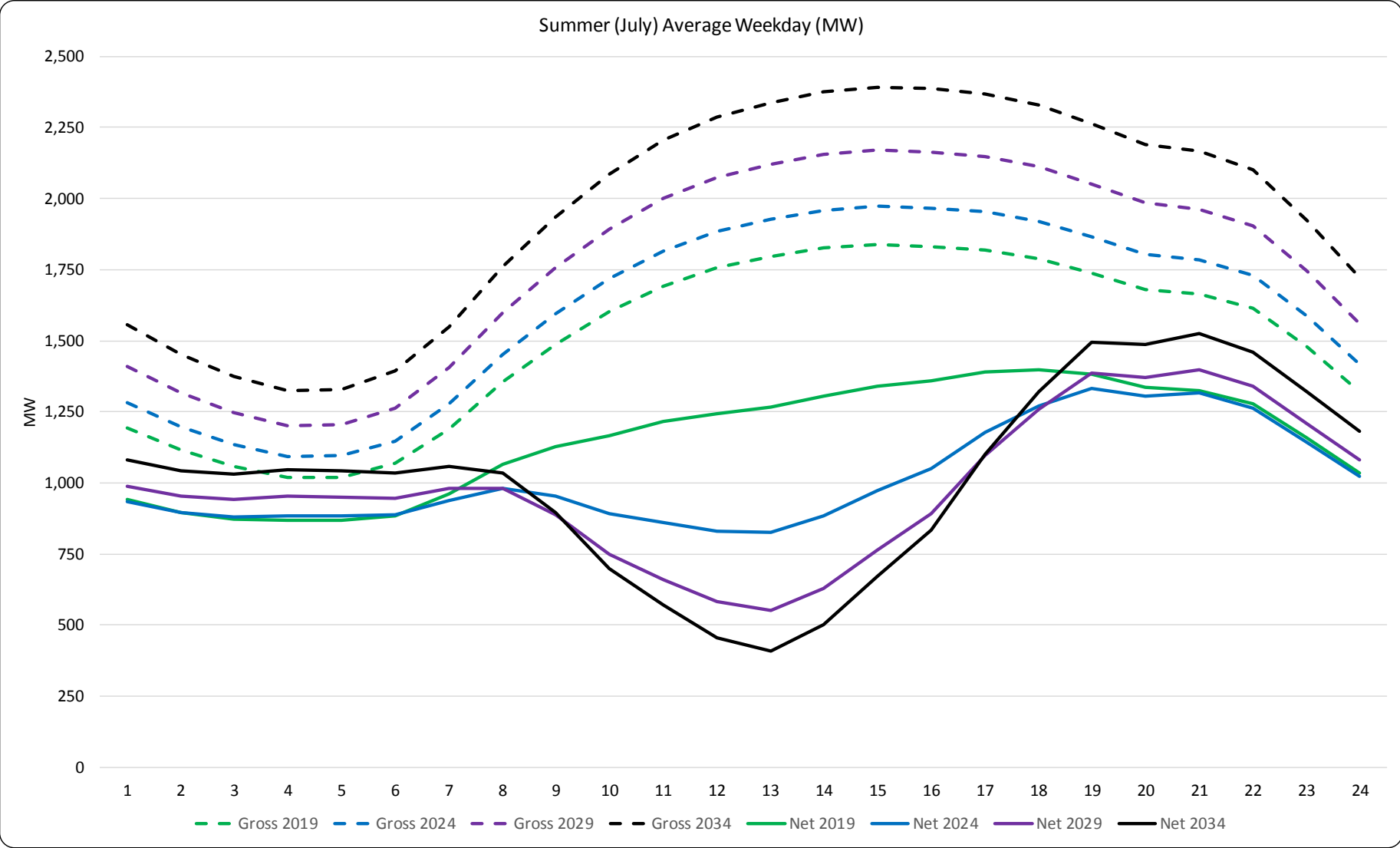
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NECO, 24 Hour Summer Peak Day
50_50, Net vs Gross

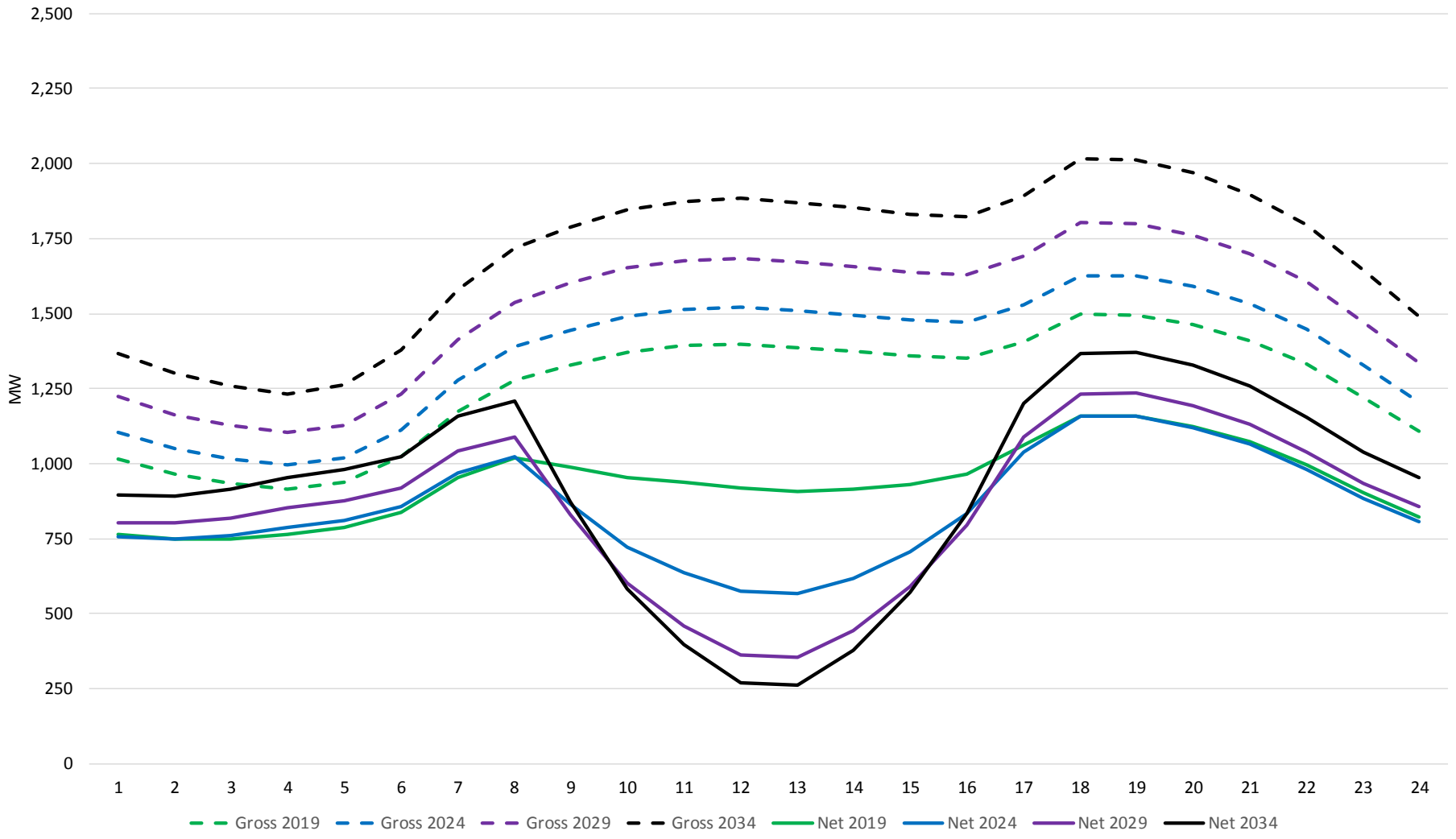


NECO, 24 Hour Winter Peak Day
 50_50, Net vs Gross

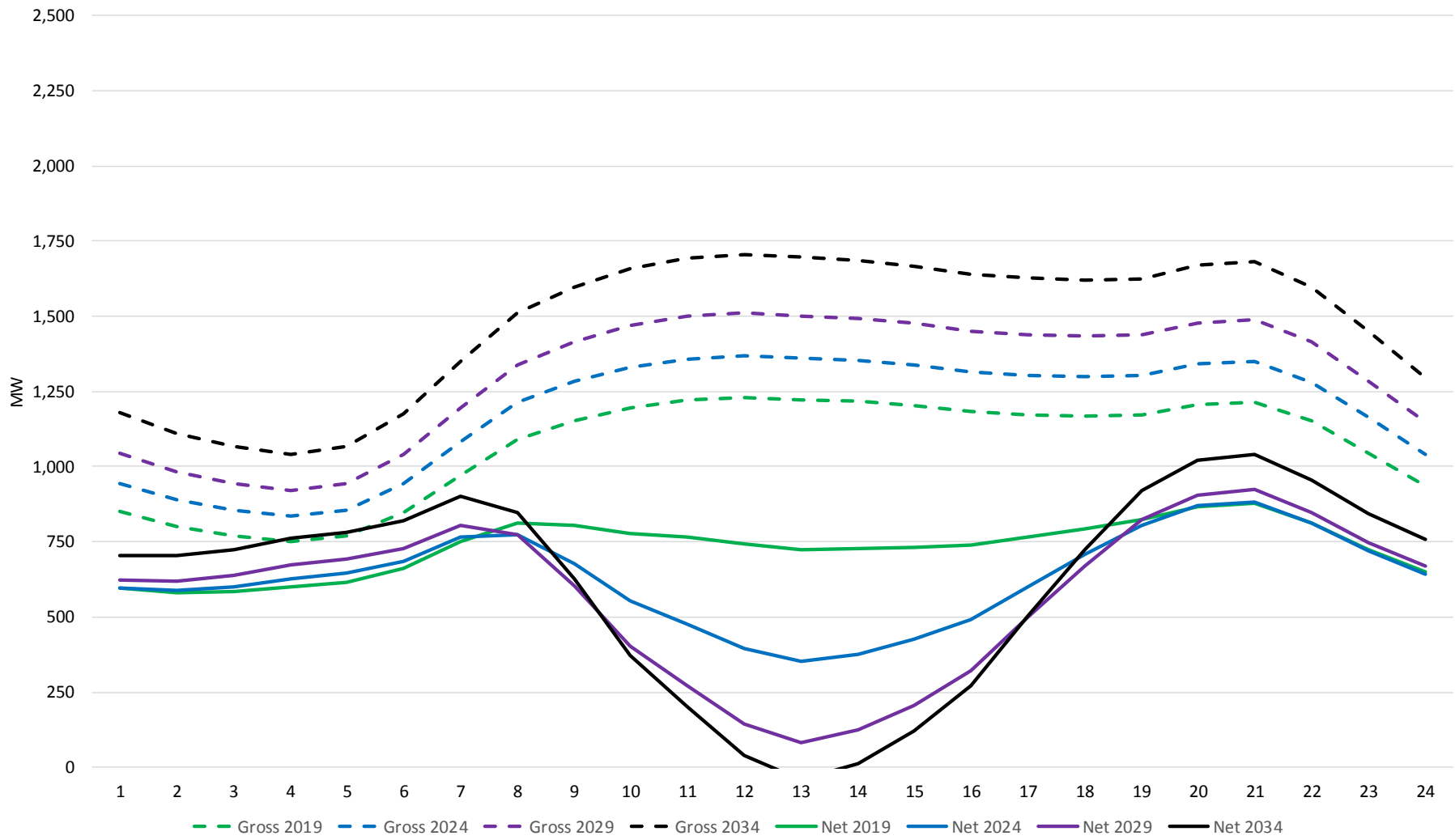




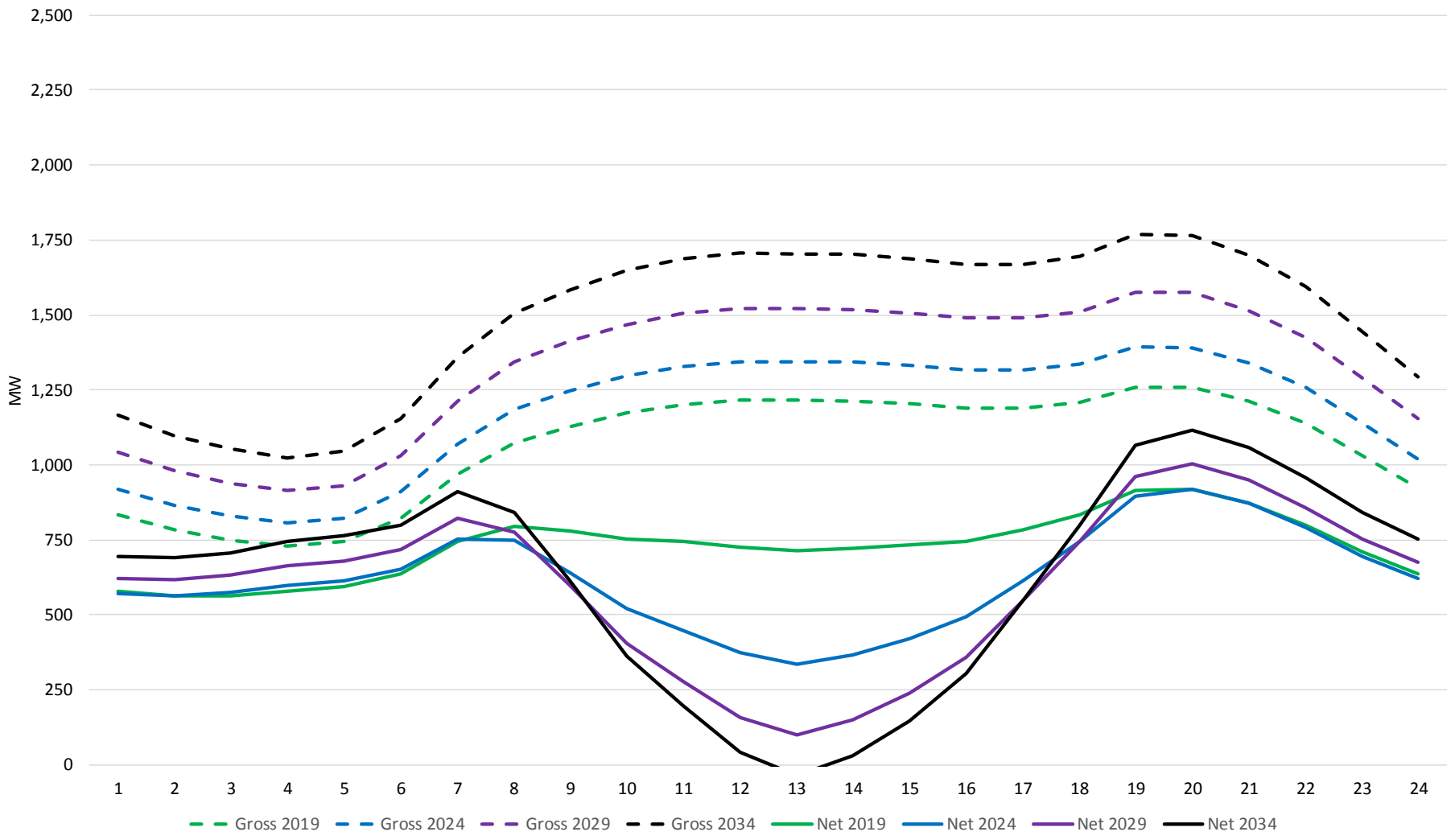
Winter (January) Average Weekday (MW)



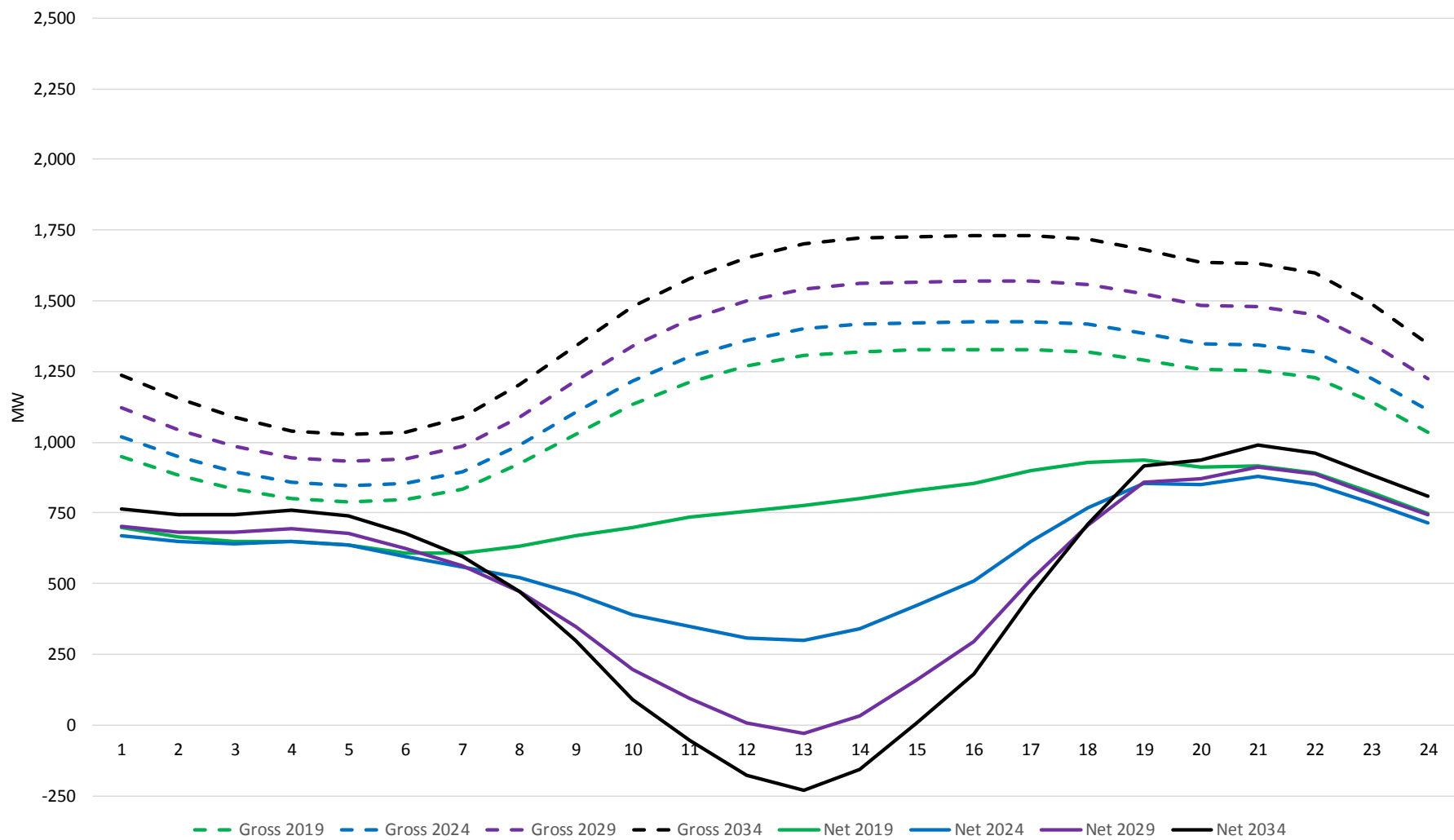
Shoulder (April) Average Weekday (MW)



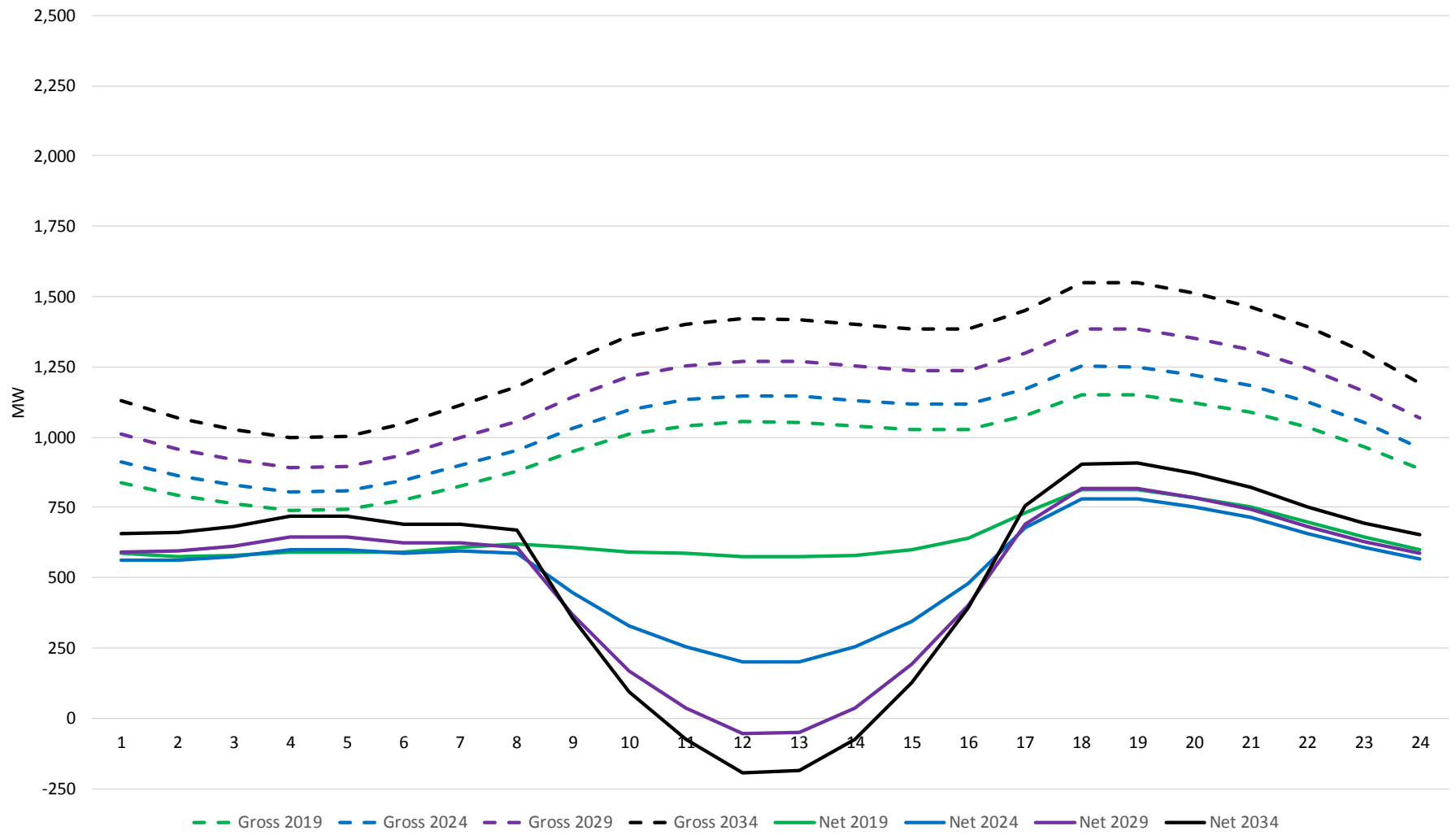
Shoulder (October) Average Weekday (MW)



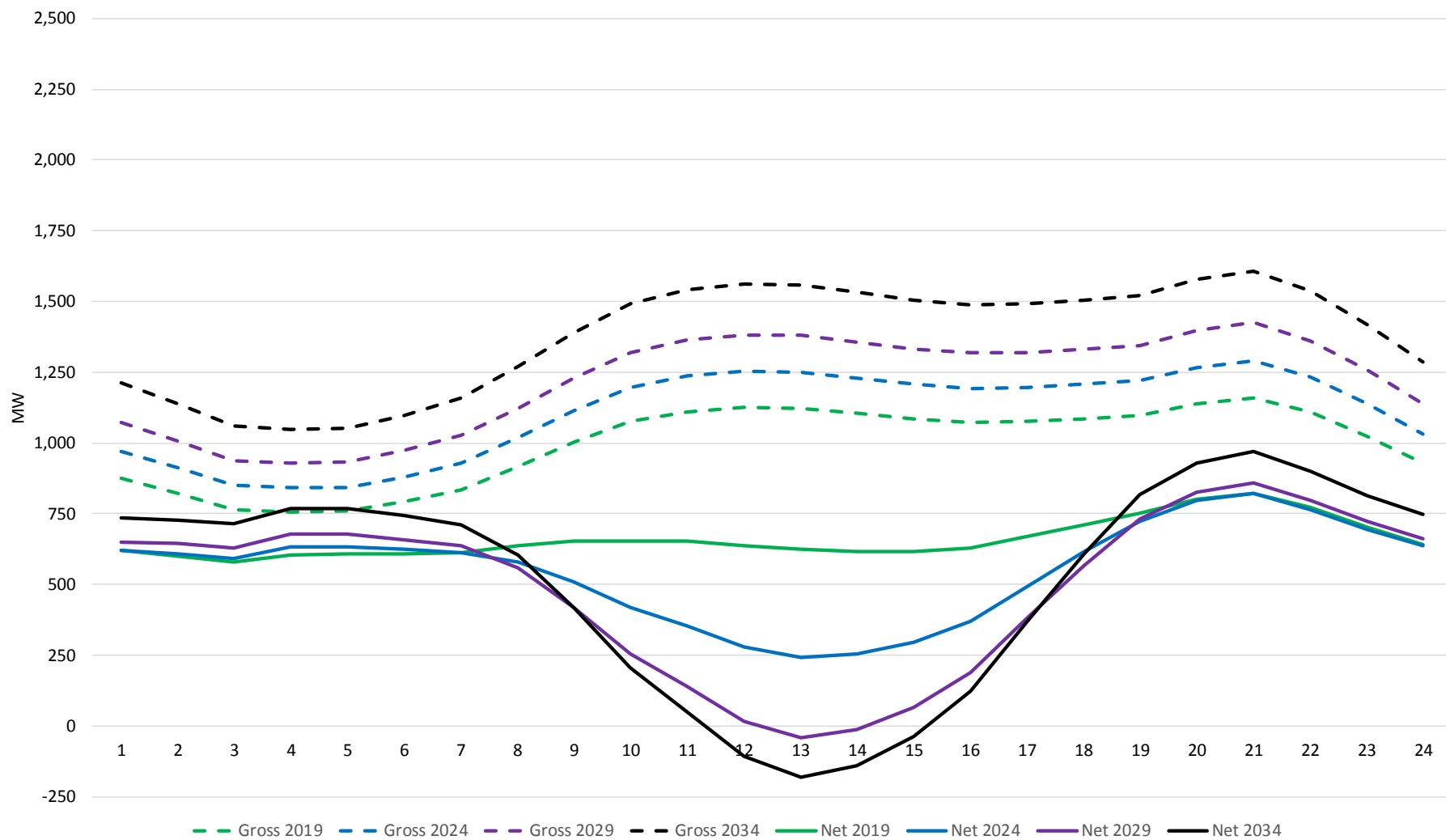
Summer (July) Average WeekEND (MW)



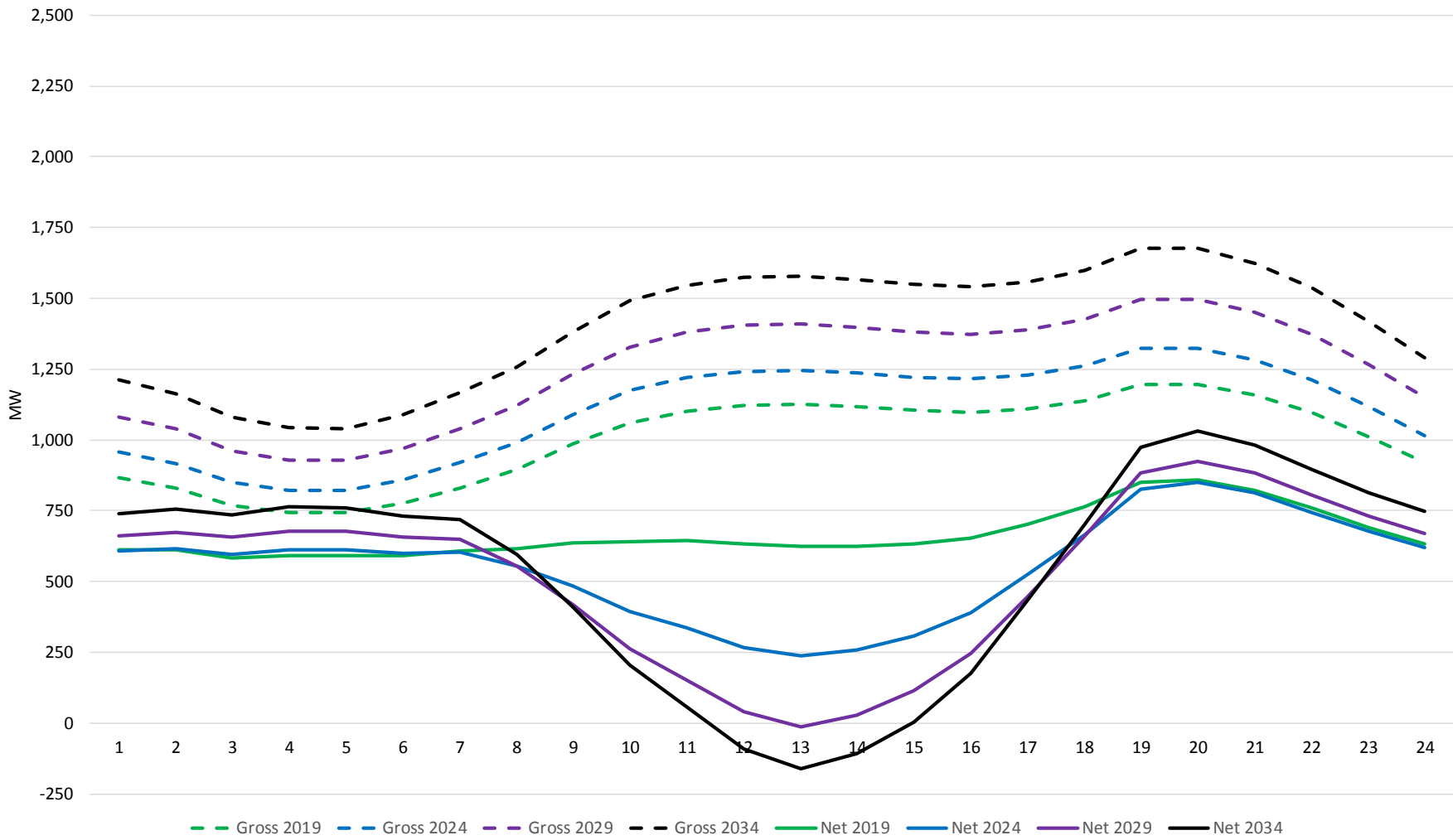
Winter (January) Average WeekEND (MW)



Shoulder (April) Average WeekEND (MW)



Shoulder (October) Average WeekEND (MW)

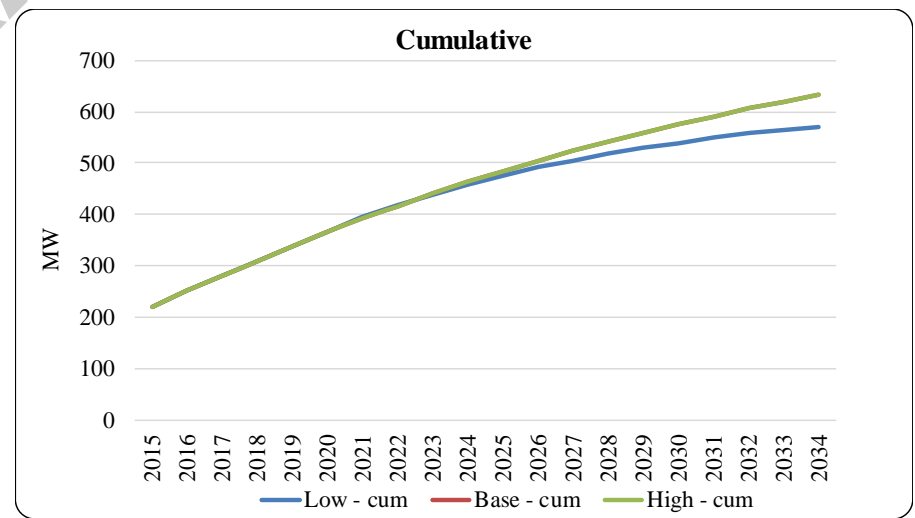
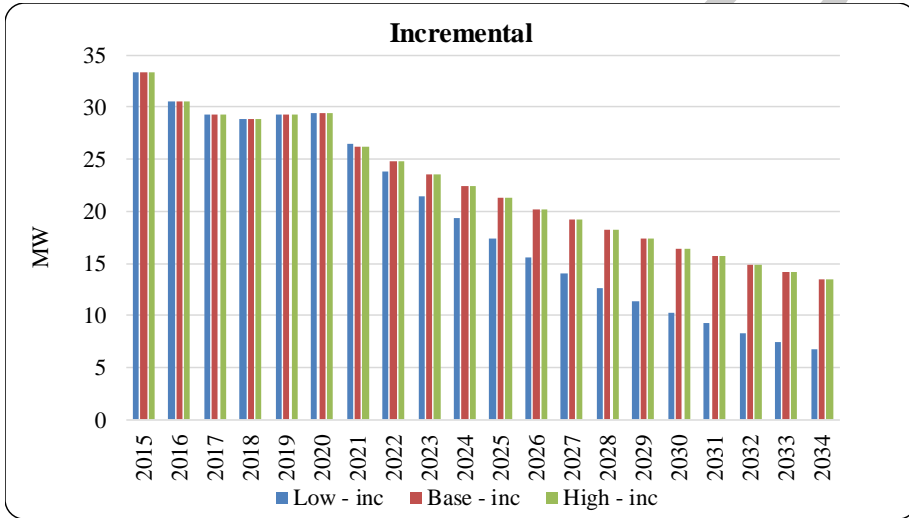


Appendix D: DER Scenarios Inputs

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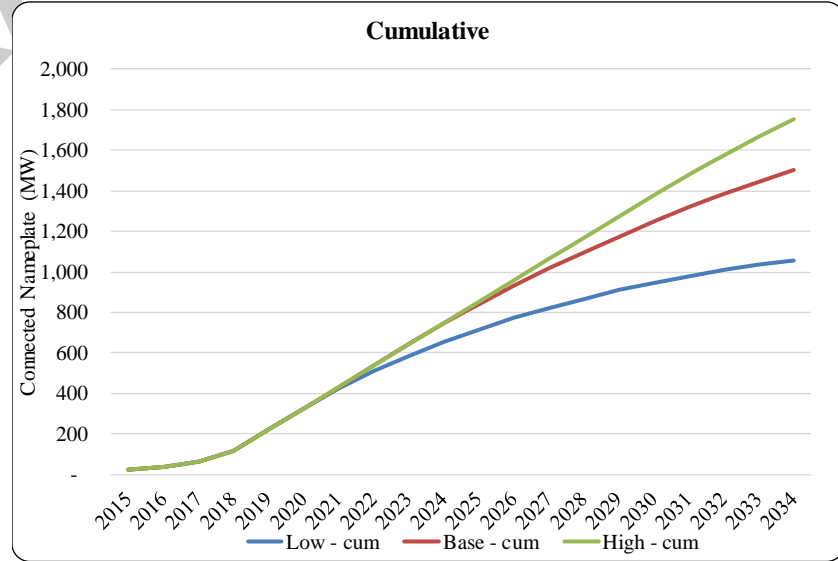
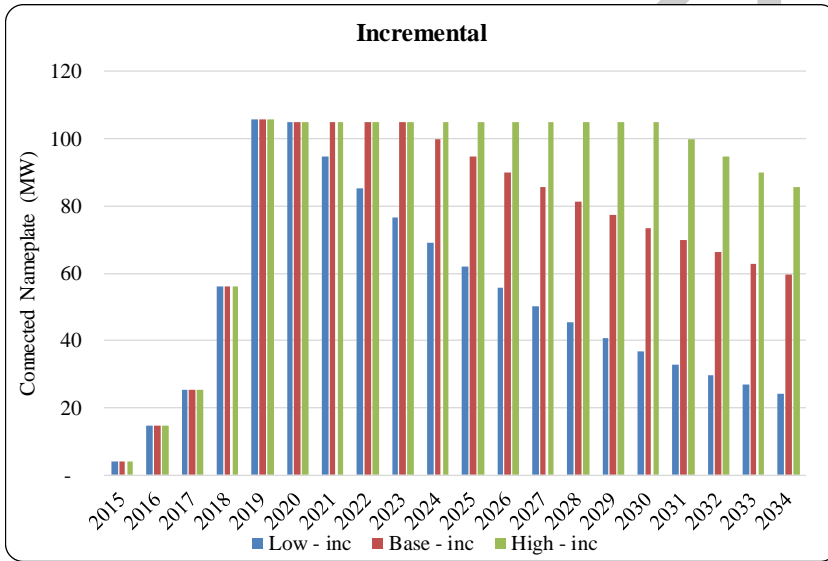
Energy Efficiency (NECO)

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



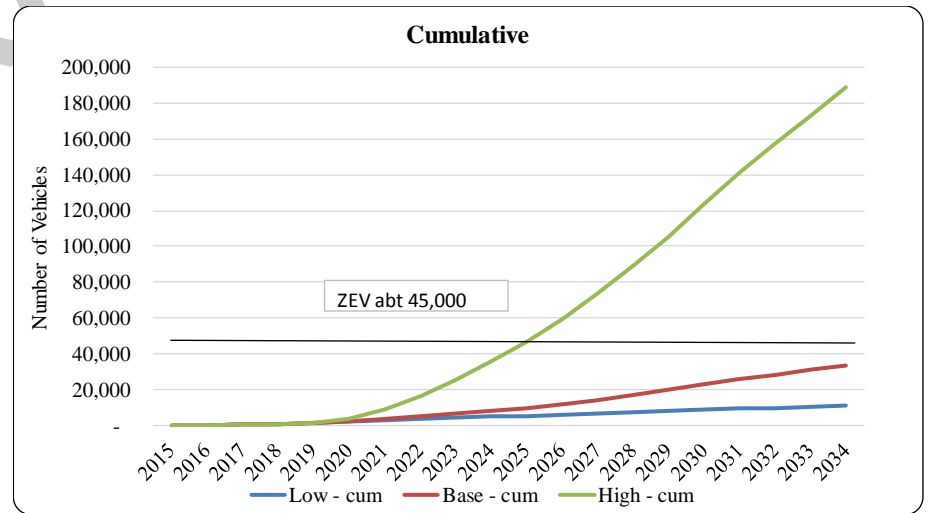
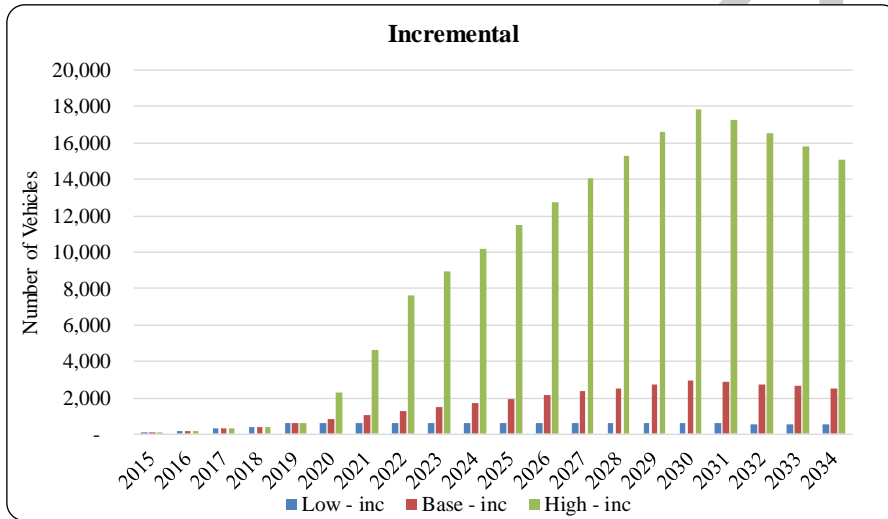
Solar – PV (NECO)

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



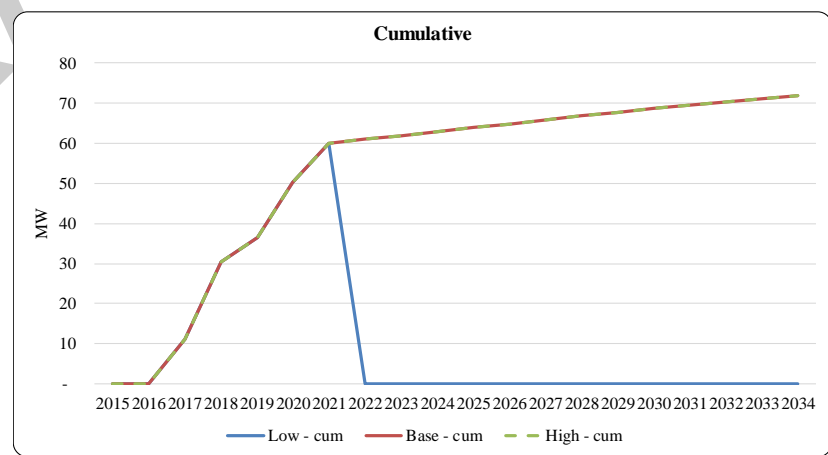
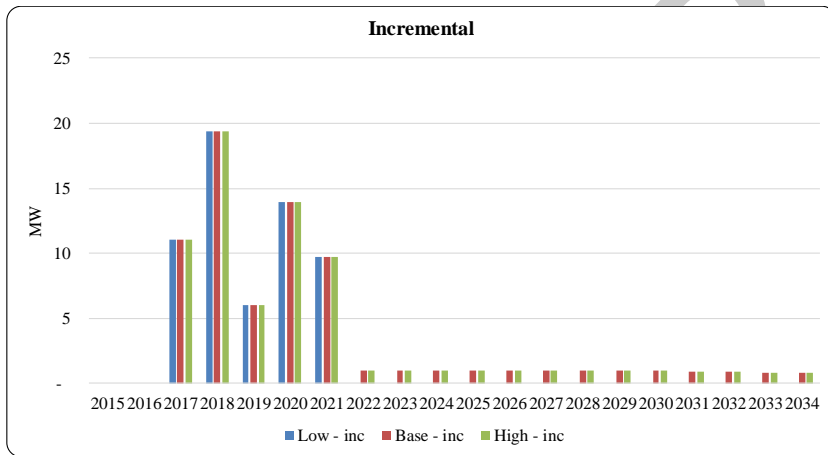
Electric Vehicles (NECO)

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

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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							
State	PSA	Zone (1)	2019 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
			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							
State	PSA	Zone (1)	2019 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
			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							
State	PSA	Zone (1)	2018/19 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
			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 – NWA Opportunities Summary Table

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2021-2023 System Reliability Procurement Three-Year Plan
Appendix 2

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 Kingstown 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 – RI NWA BCA Model

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Appendix 4 – RI NWA BCA Model Technical Reference Manual

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