

UPDATED Schedule

JPV-6

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

APPLICATION FOR APPROVAL
OF A CHANGE IN ELECTRIC AND
GAS BASE DISTRIBUTION RATES

Rhode Island Energy's Responses to
the Second Set of Data Requests from
Conservation Law Foundation

Book 1 of 1

April 1, 2026

Submitted to:
Rhode Island Public Utilities Commission
Docket No. 25-45-GE

Submitted by:



Rhode Island Energy™
a PPL company

CLF 2-1
Seasonal Heat Pump Rate Design

Request:

Please provide Rhode Island Energy's capacity planning criteria and methodology for distribution infrastructure. This should explain: (a) the planning capability criterion used (e.g., N-1 contingency, N-0, or other), (b) the loading factor threshold at which capacity upgrades are triggered (e.g., 85% of planning capability), (c) any reserve margin applied beyond the contingency criterion, (d) whether different criteria apply to different voltage levels or component types, and (e) the process by which components are identified as needing capacity upgrades and added to the capital plan.

Response:

Rhode Island Energy's Distribution Planning Guidelines are provided as Attachment CLF 2-1-1, and the Company's Study Process Guide as Attachment CLF 2-1-2. The Company also provides the following information for clarification:

- (a) The Company has normal and contingency (N-1) loading criteria.
- (b) The Company has limits of 100 percent normal loading criteria and a 16 megawatt*hour or 240 megawatt*hour load-at-risk contingency criteria for feeders and transformers/sub-transmission lines respectively.
- (c) The load-at-risk criteria can be considered the reserve margin.
- (d) The criteria are not different across voltages.
- (e) The Study Process Guide identifies how issues are identified across the system that are ultimately added to the capital plan. The projects are added to the capital plan through the Infrastructure Safety and Reliability ("ISR") Plan process.



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Distribution Planning Guide

Rev. 1

Distribution Planning Criteria Strategy

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Strategy Statement

This document describes the Rhode Island Energy Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies.

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

- 1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:
 - The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
 - Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
 - Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
 - The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
 - Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
 - Contingency risk shall be quantified via a MWhr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
 - If more than 240MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- 2.) For the loss of a sub-transmission supply line, the following planning criteria apply:
 - The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
 - Every effort must be made to return the failed sub-transmission line to service within 12 hours.
 - The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
 - Contingency risk shall be quantified via a MWhr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
 - If more than 240MWhrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

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

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

Application of these criteria will result in somewhat less load at risk than previous criteria in Rhode Island which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore, it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate.

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

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

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.
- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

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

Amendments Record

Issue	Date	Summary of Changes/Reasons	Author(s)	Approved By
0	10/14/2009	Initial draft	Curt J. Dahl John F. Duffy, Jr. Max F. Huyck Jeffery H. Smith	Patrick Hogan
1	2/15/2011	Final approved document	Curt J. Dahl John F. Duffy, Jr. Max F. Huyck Jeffery H. Smith	Patrick Hogan

Strategy Justification

1.0 Purpose and Scope

This document describes the Rhode Island Energy Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies.

A map showing Rhode Island Energy electric service territory is attached in Appendix A.

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

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of Rhode Island Energy is comprised of all lines and equipment operated at a voltage below 69kV. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within Rhode Island Energy are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level.

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

2.1.2 Sub-Transmission systems

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

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

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

2.1.3 Distribution Feeders

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

2.1.4 Secondary Networks

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

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

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for Rhode Island will be based on a regional econometric regression model that considers historic loading, weather conditions, various

economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years.

2.2.1.2 Equipment Ratings

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

Table 2 – Equipment Rating Durations

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

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

2.2.1.3 Planning Study Areas

A planning study area within Rhode Island Energy is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in RI are presented in Appendix A.

2.2.1.4 Load Flows

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

2.2.1.5 Distribution Analysis Alternatives

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

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

- e. Distribution Automation
- f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

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

2.2.2.2 Contingency N-1 substation transformer planning criteria

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

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 1OMW.
- Contingency risk shall be quantified via a MWhr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

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

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

2.2.2.4 Substation reactive support criteria

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

2.2.2.5 Impact of planned maintenance

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

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

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

2.2.3.2 Contingency N-1 sub-transmission planning criteria

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

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

2.2.3.3 Automatic line transfer systems

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

2.2.3.4 Sub-transmission reactive support criteria

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

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

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

2.2.4.2 Contingency N-1 feeder planning criteria

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

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

2.2.4.3 Automatic transfers on feeders

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

2.2.4.4 Feeder reactive support criteria

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

2.2.4.5 Feeder load balance criteria

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

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

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

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

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the Rhode Island Energy distribution standards.

2.2.6 Voltage Criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

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

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

Table 3 – Voltage Requirements

State	Upper	Nominal	Lower
Rhode Island	123	120	113

The values in Table 3 are in line with the Rhode Island Energy Overhead Construction Standards.

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

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

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

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

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

2.3.2 Methodology to prioritize capital projects

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

3.0 Risks/Benefits

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

3.1 Safety & Environmental

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

3.2 Reliability

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

3.3 Customer/Regulatory/Reputation

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

3.4 Efficiency

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

4.0 Data Requirements

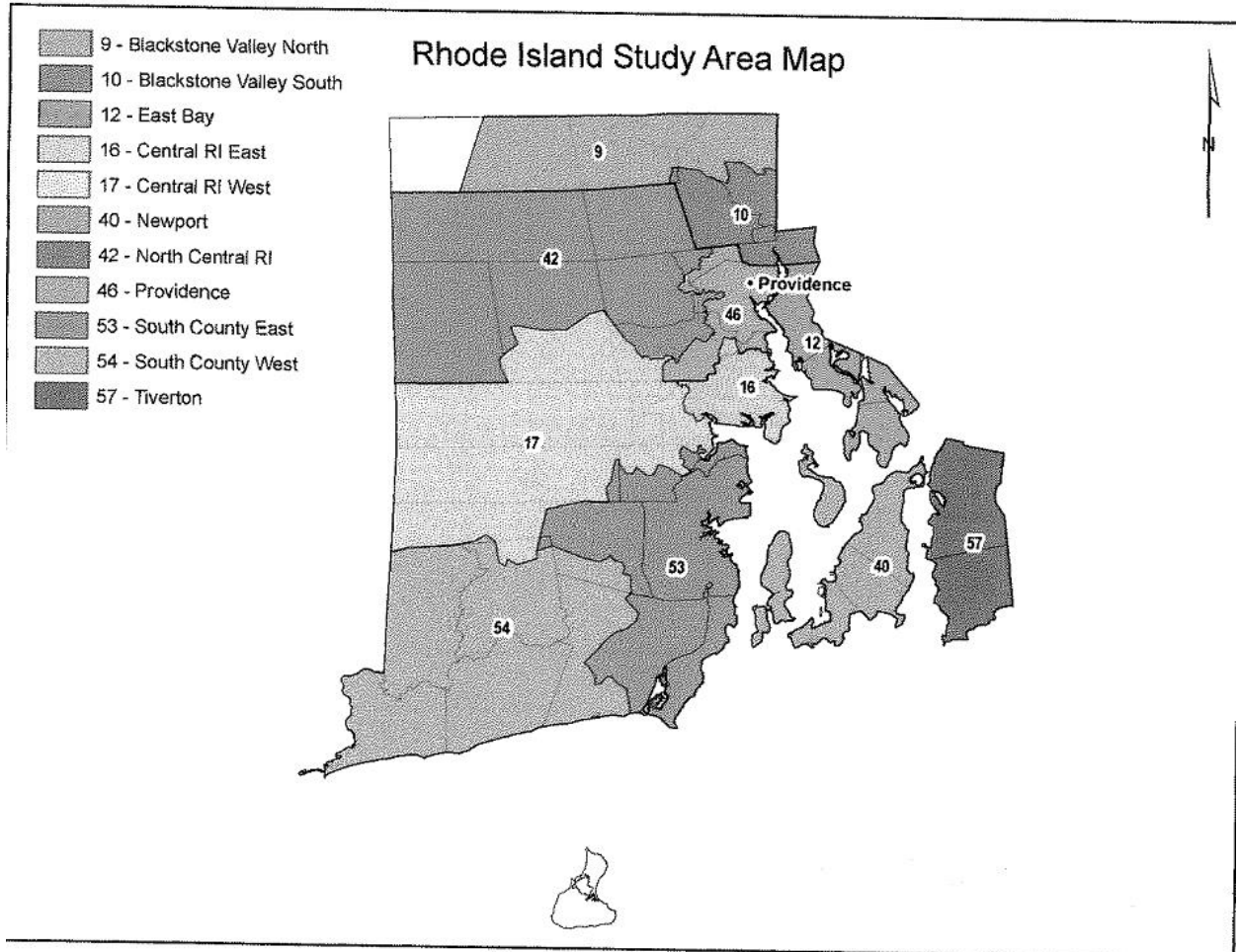
The data sources required for the proper execution of the planning strategy include:

4.1 Planning Tools:

- Cymedist (Cyme) — for radial feeder load flow and voltage analysis
- GIS — to support Cyme analysis
- PSS/e — for network load flow analysis
- FeedPro - for equipment loading and ratings
- EMS and PI

Appendix A - Distribution Planning Study Areas

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



Integrated Electric System Planning Study Process

1. Introduction

In order to maintain a consistent approach to electric system planning, it is necessary that uniform planning criteria be followed and that there is well executed coordination among internal and external stakeholder groups. This document has been updated with ‘integrated planning’ concepts including specific Distributed Energy Resource (DER) inputs and greater transmission planning consultation to provide guidance on the performance and expected work product of area planning studies.

2. Purpose

This document details the Integrated Planning and Asset Management study process for system planners, the functions that support them, and the stakeholders reliant on their work product. It is expected that execution of a well defined study process will result in timely delivery of infrastructure development recommendations having thoroughly defined project scopes that satisfy the needs and expectations of all stakeholders (especially customers). In addition, it enhances the organization’s ability to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.

3. Applicability

This guide applies to all personnel within Distribution Planning and Asset Management when assigned to work on:

- Integrated Area Studies
- Program Studies (initial or modification)
- Complex Customer Service Requirements Studies – Typically, large services requests, generally 8MW or greater and/or greater than 5MW with requirements for service redundancy

Members of departments that support the study process and associated work product development should be trained in and/or aware of this process.

Although there are many fundamental similarities, DER interconnection studies are covered a separate interconnection guide.

4. Annual Planning

The prioritization of area planning studies to be executed and the engineering analysis conducted within an area study is supported by the Annual Planning Screening Process. This process is a recurring annual effort which aides in the identification of system performance concerns. As part of this effort, the following is historically recorded or estimated:

- Area (feeder, substation, and supply line) peak loads (date, time, and value) both coincident and non-coincident with the system peak load.
- System summer peak load (date, time, and value).
- Load forecast with energy efficiency (EE), distributed generation (DG), and electric vehicle (EV) inputs as load modifiers to the peak value. These forecasts include some regional differences

As a result of evolving integrated planning needs the following information will be added or changed:

- Area (feeder, substation, and supply line) light loads (date, time, and value). Where possible, obtain 8760 hour per year PI Historian load data.
- DG existing and in-queue locations and amounts

- Separate forecasts to be obtained for base load, EE, DG, EV, and heat electrification (HE) inputs as load modifiers to the peak value. These forecasts include some regional differences
- EV and HE existing and in-queue information when possible
- Existing Demand Response (DR) programs
- Existing Energy Storage (ES) locations and amounts.

5. Milestones and Consultation Guidance

Each study generally follows a set of milestones to enable an efficient study process with robust consultation. Although stakeholder engagement can occur at any time, the following guide describes the content of each milestone and recommended consultation inputs. :

- Scoping Activities
- Initial System Assessment
- Study Kickoff
- Detailed System Assessment / Engineering Analysis
- Plan Development and Project Estimating
- Identification of Recommended Plan
- Technical Review
- Documentation
- Sanctioning

Further detail on each of these milestones follows:

5.1. Scoping

This milestone includes:

- Gather the most recent version of the Distribution Planning Guidelines (“DPG”)
 - Upon consultation with the manager, gather any other emerging guidelines that have not been formally incorporated into the DPG (ex: grid modernization or volt-var optimization guidelines).
- Gather equipment rating data, settings data, specifications data, etc.
- Gather the most recent Distribution Standards including, but not limited to:
 - Overhead conductor ratings (section 6)
 - Generic underground cable ratings (section 35)
 - Latest recloser controls (section 12)
 - Latest capacitor controls (section 15)
 - Latest sensor controls (section 15)
 - Storm Hardening (section 4)
- Define the electrical scope (lines and substations to be studied)
- Define the geographic scope (towns and portions or towns to be included in study)
- Build/update system models in CYME, PSS/e, ASPEN
- Gather the latest forecast and review/refine the area/facility load and expected load growth from the present to the study’s horizon year (typically 15 years)
 - Integrated Planning Update – Gather separate forecasts for load, EE, DG, EV, HE, DR, and ES. Gather 8760 hour yearly load cycles for each technology. If necessary, default load cycles can be used. Gather 8760 hour per year data for feeders, substation, and supply lines as available.
- Gather service territory maps
- Gather large commercial and industrial customer load data²
- Gather or request asset condition reports³
- Identify all infrastructure development limitations (ex: river, highway, state forest, etc)

² Consult with Customer and Community

³ Consult with Substation O&M Services

- Gather documentation of existing system performance concerns (ex: thermal, reliability, voltage, reactive support, arc flash, fault duty, etc.)⁴
- Gather recently completed area projects or ongoing area projects within the work plan. This will set the base year and base configuration.⁵
- Gather existing and in-queue distributed generation or distributed energy resources
- Gather state information or policies regarding distribution planning or distributed energy resources

The engineer will then develop a scope that details the study area boundaries and concerns. The study scope will be reviewed by their respective manager. The manager must approve the study scope before next steps are executed.

The final scoping activity is to request study team members. The study engineer will request formal team members from the following departments, via Study Engineering Request form.

- Transmission Planning
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering (Relay, Communications, and Controls and Integration)

The following additional departments may be expected to provide input during various stages of the study and will be included in study meetings as required:

- Substation O&M Services Operations
- Transmission Control Center and/or Regional Control Center
- Project and Program Management
- Community and Customer Management
- Distribution Design
- Safety
- Environmental
- Legal
- Real Estate

All study contributors will be provided proper accounting to charge their time in support of the study. Once a study team is formed, the study engineer will schedule the study kickoff meeting.

5.2. Initial System Assessment

Study area initial system assessment consists of a quick analysis of facilities and system performance within the identified study geographic and electric scope. As part of the assessment, the study engineer will conduct the following:

- Existing and in-queue distributed generation and distributed energy resources
- A review for compliance with Planning Guidelines:

⁴ At a minimum, include annual plan screening information. Consult with area engineering and operations experts as time allows.

⁵ For example a study starting in year X may set a base year of X+3 if substantial system modification will be completed in year X+3.

- Thermal (load vs. capability) issues using the annual planning screening spreadsheet, CYME, and PSS/e
- Voltage – using CYME, PSS/e
- Reactive Support
- Asset condition assessments and consideration of active asset programs including, but not limited to:
 - Breaker Replacement
 - EMS
 - Metal Clad Substations
 - Indoor Substations
 - Underground Cable
 - Distribution Line Inspection & Maintenance
- Screening review of arc flash and fault duty data
- Screening review of CKAIID and CKAIIFI reliability indices⁶ against state targets or average values

Initial system assessment is completed when the planner has enough information to consult with the wider group of subject matter experts and internal departments at the study kickoff. A careful balance of analysis to ensure study timeline efficiency is required. Too little analysis leaves the planner unable to lead a robust discussion during the kickoff meeting to gather those asset, operational, and construction complexities that help refine issues and generate comprehensive alternatives. Too much analysis may lead to rework by the planner should new information result from the kickoff. It is preferable that high level alternative concepts are developed during Initial System Assessment simply to generate discussion. Never should alternatives be fully developed or considered final within this step. Throughout the Initial System Assessment, it is expected that informal and regular consultations will be required with Transmission Planning, Distribution Design, Substation Engineering, Transmission Line Engineering, Substation O&M Services, and/or Operations.

5.3. Study Kickoff

The study kickoff is a meeting held to inform the larger stakeholder group that an area study is underway and to solicit inputs from those with knowledge of the system infrastructure in the area under review.

The study engineer will invite the following groups/representatives to the Kickoff meeting:

- Community & Customer Management
- Operations:
 - Distribution Line (OH & UG) Supervisors
 - Substation O&M Supervisors
 - Distribution Design
- Substation O & M Services
- System Control Center
- Project Management
- Program Management (Substation and Line)
- Distribution Engineering and Asset Management
 - Field Engineer
 - Field Engineering Manager
- Transmission Engineering and Asset Management
 - Transmission Planning Engineer

⁶ 5 year reliability data is preferred. 3 year data may be used to avoid years of significant major storm activity or significant system reconfiguration.

- Transmission Asset Management Engineer
- Transmission Line Engineering
- Substation Engineering
- Protection Engineering
- Resource Planning
 - Short Term Resource Planning
 - Long Term Resource Planning
- Product Energy Services (NWA)
- IT/ IS

The study engineer will present the following:

- Proposed study electrical and geographic scope
- Recent area studies and infrastructure development projects impacting the area
- Study area load and initial understanding of load growth expected in the area
- Known concerns in the area
- Using one-lines, possible infrastructure development plans for discussion
- Using area maps, possible distributed energy resource ideas for discussion
- Study schedule and the names of representatives of departments assigned to support it

Upon completion of this presentation, the study engineer will open the meeting for group discussion. Specific input that the study engineer is looking for includes:

- Acceptance of electrical and geographic boundaries
- Operational concerns, examples:
 - Switching flexibility
 - Restoration areas of concern (ex: rights-of-way, direct buried cables)
- Asset condition concerns not already identified
- Safety by Design
- System performance concerns not already identified, examples:
 - Reliability
 - Voltage
 - Loading
- Details on any significant near term load additions in the area not already identified
- Details on any significant distributed energy resources in the area not already identified
- Details on potential alternative ideas or concerns, examples:
 - Locations that should/could be considered for new substation development
 - Substation expansion opportunities
 - Feeder routing (new feeders and feeder ties)
 - Local issues that might impact infrastructure development options, examples
 1. Local regulations requiring underground vs. overhead construction
 2. Status of community relationships with the Company
- Details on any distributed energy resource opportunities that should be considered

Representatives assigned from all groups are expected to support the study throughout the entire process and document any concerns their department may have along the way.

All individuals invited to the kick off meeting should be asked to forward the meeting notice to any other individuals they would like to have take part in the meeting.

It is expected that the study engineer will prepare minutes of this meeting. Minutes will be shared with all those invited to participate in the meeting.

5.4. Detailed System Assessment / Engineering Analysis

The study engineer will utilize input received at the study kickoff meeting in subsequent detailed analysis and comprehensive plan development. All area distribution studies will require the same basic analysis steps.

The study engineer should look to optimize existing system performance and identify any common infrastructure development needs of the area prior to engaging in the detailed analysis associated with finalizing the development of alternative plans. Simple no-cost or low-cost system adjustments such as switching or load balancing can be progressed immediately by the planner and do not need to be formally included in the study report. Instead the study base case should be adjusted to include these simple changes.

The study engineer should:

- Conduct system fault studies, associated protective device coordination, and breaker capability reviews
- Conduct incident energy calculations (arc flash)
- Conduct system thermal assessments
- Conduct system loss studies
- Conduct system reliability assessments
- Conduct system voltage performance evaluation
- Analyze Distributed Energy Resources (DER) impacts

Typical Analysis tools:

- PSS/e load flow software for analysis of:
 - Supply system (transmission and sub-transmission)
 - Network system
- CYME and other radial distribution feeder analysis software
- CYME, ASPEN, and other protective device coordination software including short circuit analysis
- ArcPro for Arc Flash analysis
- GIS systems
- Annual Planning Screening Spreadsheets
- Equipment ratings programs
- Cascade and other asset information systems

Note that the presentation of results and defense of recommendations is significantly enhanced by the functionality of these tools (particularly load flow and radial distribution feeder analysis software). These tools will strengthen response to questions posed during the review of recommendations. These tools enable quick evaluation of “what if” questions that could otherwise cause unacceptable delays in study delivery.

5.5. Plan Development and Project Estimating

Once the engineering analysis is performed, the study engineer develops and refines alternative infrastructure development and non-wires alternative plans and updates associated plan one-lines. The plans should be technically comparable to the furthest extent possible. Infrastructure and non-wires alternatives can be combined to create comparable plans.

The following team members/departments will provide a feasibility review of these one-lines:

- Field Engineer
- Substation Engineer
- Transmission Line Engineer
- Distribution Design Engineer
- Operations
- Transmission Planning

OPTIONAL - It is suggested the planner gather all internal stakeholders⁷ at a Plan Development meeting to review and gain acceptance of the various plans immediately prior to requesting estimates. It is important that the various engineering functions understand the interrelationship between their individual portions of the comprehensive plans. Without this review, it is often difficult for the engineering functions to understand the segmented nature of estimate requests.⁸

As the one-lines and plans are modified with this cross functional input, engineering analysis will be refined as needed to accommodate for any scope changes. Once the plans and one-lines are completed, the study engineer will request study estimates from the respective team members (substation engineer, transmission line engineer, and distribution design engineer) for all alternative plans.⁹

It is expected that estimates will be returned within 8-12 weeks of the request date. Estimators will use primary equipment scope and known field conditions along with recent costs for comparable projects to develop estimates. Field visits are not required, but are encouraged especially if constructability or future system maintenance (ex. R/W accessibility) is a concern. Estimates are expected to be suitable for plan comparison/selection and enable initial partial sanction of more detailed engineering activities. Substation and transmission line conceptual engineering reports and estimates may be requested if they can be completed within the 8-12 weeks. Distribution line estimates can be completed by the planner using the Company's Success Enterprise estimating tool and can be considered at a conceptual level of accuracy.

Note: When considering alternate locations for a new substation. The site where a new substation will be constructed should be selected by the sponsor with input from the project team. Where alternate sites are required for regulatory reasons or are desirable for other reasons, those alternate sites should also be selected by the sponsor. In addition to the engineering requests, sites should be assessed for other flaws that could warrant them unsuitable for use. These "due diligence" assessments for potentially "fatal flaws" should be performed by the following departments and reported to the sponsor: Environmental, Real Estate, Legal (Siting), Project Management, and Construction or Operations.

While estimates are under development, the planner should organize and document the technical benefits and issue resolution of each alternative. The planner has discretion to the level of analysis for alternatives that are expected to be economically non-competitive.

Once the study estimates are returned, the study engineer will review and finalize the identified plans. Study team members will be asked to note their agreement with the scope of projects estimated.

⁷ Similar to the kickoff meeting invite list

⁸ For example a substation request that asks for a common item such as a capacitor bank to be estimated separately from a feeder position which may be an alternative plan.

⁹ Requests should be well documented with clearly defined one-line scope diagrams, using

5.6. Identification of Recommended Plan

As part of this phase, the study engineer reviews the various alternatives with costs, identifies, and finalizes a recommended plan. Once the recommended plan is identified, the study engineer completes (with team member assistance as required):

- Economic comparison of plans
- Technical comparison of plans if not equivalent
- Performance of an environmental and safety review of recommended plan
- Identification of the system outages required to implement the recommended plan
- Statement or summary of alignment with Climate Resiliency standards¹⁰
- If not formally evaluated as a criteria, strategy, or program within the study, include a statement or summary of alignment with potential or pending Grid Modernization concepts.¹¹
- Review of the recommended plan project implementation schedule¹²

The planner should summarize recommended plan risks to the furthest extent possible. For example, permitting or site acquisition delay risks could be noted with the system issues that may result. Potential mitigation concepts, including acceptance of risk, can be described. This is not intended to be an exhaustive review and it is noted that significant internal department consultation and support is necessary. Instead, this risk analysis is only intended to help or guide future efforts.

Once all this analysis is completed and documented, the study engineer updates the project team members on the final recommended plan.

5.7. Technical Review

This meeting will be held once the planner has completed the majority of the study analysis and after an internal review in Distribution Planning and Asset Management has been completed, but prior to the formal study document approval process.

The primary purpose of this meeting is to give those who will be asked to approve the area study report an opportunity to hear a presentation and ask their own questions on the overall study effort. It is expected that this meeting will facilitate the study report approval process that will in most instances follow soon after.

The presentation will provide a description of the issue identification efforts and a comparison of all plans, including estimated costs, describing the advantages and disadvantages of each.

The planner will cover the following topics in presentation format during the meeting. The presentation will be split (between Distribution Planning and Transmission Planning) if study responsibility is split.

- Study scope (electric system one-lines and map of area)
- Study area load and load growth
- Additional study assumptions
- System performance concerns identified (existing and predicted)
- Plans considered to address concerns with detailed description of the scope of proposed projects, time and cost required to implement, technical differences, as well as unresolved stakeholder concerns

¹⁰ All recommendation should be built to the latest storm hardening and substation flood mitigation standards

¹¹ For example, use of latest controls that prevent near term obsolescence

¹² Consult with Long Term Resource Planning for implementation schedule and cash flow assistance.

- Plan recommended to address concerns with detailed description of the scope of proposed projects, time, and cost required to implement

Meeting participants are expected to constructively challenge study assumptions and analysis (ex. load growth assumptions, load flow models, equipment ratings, interpretation of planning criteria in determining violations, etc.) and the plans developed to address area concerns. If a specific project's scope of work is in question (ex. asset condition concerns not addressed) and can not be resolved in this meeting, the Study engineer will set up subsequent meetings with the project team for more detailed discussion and problem resolution.

The following groups/representatives are part of the Technical Review meeting governance:

- Asset Management including:
 - Director Asset Management and Engineering
 - Manager of Asset Management
 - Director of Transmission Planning and Asset Management
 - Manager of Transmission Planning
- Operations including:
 - Director of Distribution Design
 - Director of Operations
 - Manager of Regional Field Engineering
- Dispatch and Control, including:
 - Manager of Control Center Operations
- Jurisdictional Leadership, including:
 - Jurisdictional President
 - Community and Customer Management, Director
- Representatives assigned from all groups that are supporting the study (attendance required)
- Vice President of Electric Operations

5.8. Documentation

The area study report is the primary documentation delivered upon completion of the area study. This report becomes a source document for many other forms and reports (used both internally and externally). As such, the importance of form and order in reports be as consistent as possible.

In order to properly complete the report template, the study engineer will need to have done the work necessary to prepare the following general report sections:

- Executive summary, including:
 - Explanation of why the study was done and the major concerns/needs for the area
 - A brief description of the alternatives considered
 - A brief description of the recommended plan
 - Reasons for the recommendation
 - Cost and cash flow of the recommended plan
- Introduction, including:
 - Purpose statement
 - Problem statement
- Background, including:
 - A statement on all items gathered in Section 4.1
 - Versions or dates of guidelines, standards, forecasts, databases, screening work, and software used
- Problem/Issue Identification, including:
 - A summary of all analysis done in Sections 4.2 and 4.4

- Plan Development, including:
 - A summary of all efforts done in Section 4.5
- Description of recommended plan, including:
 - A summary of the comparative analysis and conclusions made during Section 4.6
 - A clear summary of the sequencing of projects, project dependencies, proposed cash flow, and risks.
- Conclusion and factors affecting future studies
- Appendices, including but not limited to:
 - Geographic study area maps
 - One-line diagrams for stations, sub-transmission systems, and circuit tie maps - base case and recommended plan
 - Feeder rating sheets
 - Existing and in-queue Distributed Generation tables
 - Annual Plan screening tables – base case and recommended plan
 - CYME, PSSE, and Aspen screens and tabular exports - base case and recommended plan
 - Strategy or program tabular details including criticality rankings
 - Arc flash tables - base case and recommended plan
 - Reliability indices tables
 - Fault duty analysis tables - base case and recommended plan
 - Estimate data

Appendix A and B of this document provide a detailed outline of area study and program study report content respectively.

Study reports will be issued following the Study Results presentation (and resolution of any issues it raised). The report will be electronically issued with a cover letter to the following individuals for approval:

- Respective Manager of Distribution Asset Management
- Respective Director of Distribution Planning and Asset Management
- Vice President Asset Management

The study report will be electronically stored on Distribution Planning and Asset Management's SharePoint site.

It is expected that the Customer and Community Management group will communicate the recommended plan with external stakeholders as appropriate. Consultation with jurisdictional leader for approval of the external communication plans is required.

5.9. Sanctioning

Per the PPL Delegation of Authority Procedure, all investments must receive proper Delegation of Authority (DOA). The PPL DOA procedure and the RI Electric Engineering Sanctioning Guidance document can be found on the HR documents SharePoint and RI Regional Engineering SharePoint sites respectively.

It is expected that the study engineer will, upon study approval, seek initial sanction of any recommended projects having forecasted spending within the next three fiscal years. Long Term Resource Planning will track and schedule initial sanctioning activities for all projects that will be initiated beyond the first two full fiscal years from study completion.

6. Appendix A

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Appendix B

Program Report Table of Contents

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- 6. Factors Requiring Program Review**
- 7. Appendix**

CLF 2-2
Seasonal Heat Pump Rate Design

Request:

Please provide the latest feeder table, as provided to the Division in the most recent Infrastructure, Safety and Reliability docket, including summer and winter peaks historically from 2021-2025 and 2026-2035 forecasts.

Response:

Attachment CLF 2-2-1 contains feeder and transformer peak tables, which are also provided in the FY27 Infrastructure, Safety and Reliability ("ISR") Plan, Docket No. 25-54-EL. The included customer count data by feeder is for engineering purposes and may not match exactly the customer count data provided in other Company filings in this docket. A contingency load-at-risk column has been provided indicating feeders and transformers that currently have load-at-risk in excess of planning guidelines. "Borderline" feeders and transformers are those items within 80 percent of the planning guidelines.

Winter peaks have not been provided as the system is currently summer limited and is expected to remain summer limited into the late 2030s. Therefore, the Company does not compile winter peak tables for planning purposes. For ad-hoc winter analysis, the Company uses a 70 percent factor on the summer peak. To provide further insight on winter loading, the Company's latest Electric Peak Forecast is provided as Attachment CLF 2-2-2. This is a top-down forecast in which the state-wide forecast is applied relatively evenly across the system. This is currently done for the summer data and would be the same if winter feeder peaks were developed. Recognizing the uniform application of the forecast and using the 2024 95-5 winter peak value¹ of 1,343 megawatts divided by the 2024 95-5 summer peak value² of 1,884 megawatts equals 71 percent, demonstrating alignment with the Company's assumptions.

¹ NECO Winter Peak Table, Appendix A

² NECO Summer Peak Table, Appendix A

Line No.	Study Area (a)	Substation (b)	Transformer (c)	Voltage (kV) (d)	Feeder (e)	SN Rating (Amps) (f)	Total Customers (g)	# Com Cust (h)	# Res Cust (i)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2026	2035	
										Amps (j)	Amps (k)	Amps (l)	Amps (m)	Amps (n)	Amps (o)	Amps (p)	Amps (q)	Amps (r)	Amps (s)	Amps (t)	Amps (u)	Amps (v)	Amps (w)	Amps (x)	Contingency Load-at-Risk (y)	Contingency Load-at-Risk (z)	
1	Blackstone Valley North	NASONVILLE	271	13.8	127W40	484	2941	262	2679	295.0	268.0	355.1	356.2	413.5	420	418	417	415	415	415	417	419	421	424			
2	Blackstone Valley North	NASONVILLE	271	13.8	127W41	515	682	96	586	224.0	236.0	265.9	286.6	307.0	305	303	302	301	301	301	302	303	305	307			
3	Blackstone Valley North	NASONVILLE	271	13.8	127W42	459	1042	82	960	354.0	298.0	285.8	279.3	300.1	298	296	295	294	294	294	295	297	299	300			
4	Blackstone Valley North	NASONVILLE	271	13.8	127W43	559	3	2	1	411.0	479.0	454.4	478.4	512.4	509	506	504	503	502	503	504	506	510	513	Yes	Yes	
5	Blackstone Valley North	RIVERSIDE 8	81TR	13.8	108W51	499	1526	305	1221	339.0	333.0	305.7	321.2	354.0	351	350	348	347	347	347	348	350	352	354			
6	Blackstone Valley North	RIVERSIDE 8	81TR	13.8	108W53	499	2644	440	2204	376.7	378.0	370.0	369.7	396.0	393	391	389	388	388	388	388	390	391	394	396		
7	Blackstone Valley North	RIVERSIDE 8	81TR	13.8	108W55	510	188	38	150	185.0	185.7	177.3	171.5	183.7	182	181	181	180	180	180	181	182	183	184			
8	Blackstone Valley North	RIVERSIDE 8	82TR	13.8	108W60	365	0	0	0	325.3	314.0	267.5	292.8	313.6	311	310	308	308	307	308	309	310	312	314			
9	Blackstone Valley North	RIVERSIDE 8	82TR	13.8	108W61	500	2380	276	2104	194.3	191.7	189.5	185.6	198.8	197	196	196	195	195	195	196	196	198	199			
10	Blackstone Valley North	RIVERSIDE 8	82TR	13.8	108W62	515	1576	222	1354	122.7	121.0	121.8	110.0	127.8	127	126	126	125	125	125	126	126	127	128			
11	Blackstone Valley North	RIVERSIDE 8	82TR	13.8	108W63	515	1082	129	953	110.3	107.0	107.9	103.9	134.3	133	133	132	132	132	132	132	132	133	134			
12	Blackstone Valley North	RIVERSIDE 8	82TR	13.8	108W65	520	3688	408	3280	333.7	324.7	310.1	309.2	331.2	329	327	326	325	324	325	326	327	329	332			
13	Blackstone Valley North	STAPLES 112	1TR	13.8	112W41	515	1934	123	1811	220.3	197.7	194.7	168.5	192.5	191	190	189	189	189	189	189	190	191	193			
14	Blackstone Valley North	STAPLES 112	1TR	13.8	112W42	440	3076	262	2814	403.0	375.3	344.9	386.0	413.4	410	408	407	406	405	406	407	409	411	414			
15	Blackstone Valley North	STAPLES 112	1TR	13.8	112W43	515	999	110	889	199.0	189.3	158.4	186.4	199.6	198	197	196	196	196	196	196	197	199	200			
16	Blackstone Valley North	STAPLES 112	1TR	13.8	112W44	428	2387	84	2303	401.3	384.7	338.4	369.7	396.0	393	391	389	388	388	388	388	390	391	394	396	Yes	Yes
17	Blackstone Valley North	HIGHLAND PARK #200	1TR	13.8	200W1	465	33	32	1	197.0	210.3	200.6	195.9	229.9	221	220	219	219	218	219	219	220	222	223			
18	Blackstone Valley North	HIGHLAND PARK #200	2TR	13.8	200W2	530	35	32	3	107.7	113.7	102.0	104.3	111.7	111	110	110	109	110	110	110	110	111	112			
19	Blackstone Valley North	HIGHLAND PARK #200	1TR	13.8	200W3	530	28	10	18	139.7	174.0	173.4	168.1	180.0	179	178	177	177	176	177	177	178	179	180			
20	Blackstone Valley North	HIGHLAND PARK #200	2TR	13.8	200W4	530	206	12	194	102.3	99.7	69.6	44.7	47.8	47	47	47	47	47	47	47	47	48	48			
21	Blackstone Valley North	HIGHLAND PARK #200	1TR	13.8	200W5	530	3853	361	3492	377.7	354.3	333.3	330.8	357.4	352	350	348	348	347	348	349	350	352	355			
22	Blackstone Valley North	HIGHLAND PARK #200	2TR	13.8	200W6	515	383	59	324	188.3	178.7	189.3	159.0	170.3	169	168	167	167	167	167	168	168	169	170			
23	Blackstone Valley North	WOONSOCKET	1TR	13.8	26W1	505	1536	105	1431	216.0	295.3	302.4	312.2	190.7	189	188	188	187	187	187	188	188	190	191			
24	Blackstone Valley North	WOONSOCKET	1TR	13.8	26W3	507	2306	327	1979	362.7	357.7	371.5	348.5	419.3	416	414	412	411	411	411	411	413	414	417	420		
25	Blackstone Valley North	WOONSOCKET	1TR	13.8	26W5	513	2931	311	2620	319.7	313.7	309.6	290.6	368.2	365	364	362	361	361	361	362	364	366	369			
26	Blackstone Valley North	WOONSOCKET	1TR	13.8	26W7	515	282	53	229	208.3	300.0	302.2	291.8	172.4	171	170	170	169	169	169	170	170	172	173			
27	Blackstone Valley South	PAWTUCKET #1	73ATR	13.8	107W60	200	187	117	70	47.0	41.0	35.2	41.3	44.0	44	44	44	43	43	43	44	44	44	44			
28	Blackstone Valley South	PAWTUCKET #1	73ATR	13.8	107W61	343	2421	311	2110	0.0	269.4	257.8	236.0	284.0	282	280	279	278	278	278	279	280	282	284			
29	Blackstone Valley South	PAWTUCKET #1	73ATR	13.8	107W62	480	2532	365	2167	265.0	246.7	307.5	364.3	415.0	412	410	408	363	363	363	364	366	368	371			
30	Blackstone Valley South	PAWTUCKET #1	73ATR	13.8	107W63	515	3185	380	2805	323.0	247.0	230.0	230.8	247.0	245	244	243	242	242	242	243	244	246	247			
31	Blackstone Valley South	PAWTUCKET #1	73ATR	13.8	107W65	200	19	19	0	59.9	55.5	45.9	49.0	49	49	49	48	48	48	48	48	49	49	49			
32	Blackstone Valley South	PAWTUCKET #1	73ATR	13.8	107W66	389	3335	419	2916	292.0	316.8	288.6	254.8	301.0	299	297	296	295	295	295	296	297	299	301			
33	Blackstone Valley South	PAWTUCKET #1	74TR	13.8	107W80	279	2071	232	1839	240.0	224.9	206.4	209.5	224.0	223	222	221	220	220	220	221	222	223	225			
34	Blackstone Valley South	PAWTUCKET #1	74TR	13.8	107W81	365	1327	243	1084	369.0	333.2	247.3	193.5	256.0	254	253	252	254	253	254	254	256	257	259			
35	Blackstone Valley South	PAWTUCKET #1	74TR	13.8	107W83	367	1426	159	1267	234.0	195.9	179.4	189.6	284.0	282	281	279	279	278	279	280	281	283	284			
36	Blackstone Valley South	PAWTUCKET #1	74TR	13.8	107W84	200	0	0	0	0.0	34.6	41.0	47.9	51.0	51	51	50	50	50	50	51	51	51	51			
37	Blackstone Valley South	PAWTUCKET #1	74TR	13.8	107W85	335	701	67	634	111.0	119.2	128.9	104.2	280.0	299	297	296	295	295	295	296	297	299	301			
38	Blackstone Valley South	VALLEY	21TR	13.8	102W41	515	177	122	55	180.0	180.5	155.0	153.0	164.0	163	162	161	121	121	121	121	122	122	123			
39	Blackstone Valley South	VALLEY	21TR	13.8	102W42	400	3117	266	2851	389.0	355.1	301.2	316.2	339.0	336	335	333	332	332	332	333	335	337	339			
40	Blackstone Valley South	VALLEY	21TR	13.8	102W44	375	2602	404	2198	236.0	302.4	237.4	248.4	266.0	277	276	275	274	273	274	275	276	278	279			
41	Blackstone Valley South	VALLEY	22TR	13.8	102W50	306	364	132	232	19.0	18.0	158.6	132.4	142.0	141	140	139	197	197	197	198	199	200	201			
42	Blackstone Valley South	VALLEY	22TR	13.8	102W51	325	2397	244	2153	336.0	364.5	274.1	288.1	309.0	306	305	303	303	302	303	304	305	307	309			
43	Blackstone Valley South	VALLEY	22TR	13.8	102W52	350	2636	340	2296	132.0	138.2	129.1	171.4	184.0	182	181	181	203	203	203	204	205	206	207			
44	Blackstone Valley South	VALLEY	22TR	13.8	102W54	340	2343	86	2257	310.0	296.7	283.3	296.7	318.0	315	314	313	312	311	312	313	314	316	318	Borderline	Borderline	
45	Blackstone Valley South	WASHINGTON	261	13.8	126W40	515	157	20	137	257.0	270.9	264.4	307.8	347.0	344	342	341	340	340	340	341	343	345	347			
46	Blackstone Valley South	WASHINGTON	261	13.8	126W41	520	2325	243	2082	494.3	444.0	404.5	368.2	408.0	405	403	401	400	400	400	401	403	406	408			
47	Blackstone Valley South	WASHINGTON	261	13.8	126W42	490	538	241	297	261.0	293.5	243.7	350.5	375.0	418	416	414	413	412	413	414	416	418	421		Borderline	
48	Blackstone Valley South	WASHINGTON	262	13.8	126W50	528	1547	126	1421	405.7	398.1	361.5	370.7	397.0	394	392	390	389	389	389	391	392	395	397			
49	Blackstone Valley South	WASHINGTON	262	13.8	126W51	515	1845	211	1634	450.7	446.1	328.1	337.5	447.0	444	442	440	439	438	439	440	442	445	448	Yes	Yes	
50	Blackstone Valley South	WASHINGTON	262	13.8	126W53	583	7	7	0	25.0	22.8	24.1	21.8	23.0	23	23	23	23	23	23	23	23	23	23			
51	Blackstone Valley South	WASHINGTON	262	13.8	126W54	530	802	106	696	382.7	377.4	414.3	408.3	449.0	445	443	441	440	439	440	441	443	446	449			
52	Blackstone Valley South	CENTRAL FALLS	SOUTH BANK	4.16	104I1	350	148	20	128	29.3	32.8	28.3	33.2	36.0	35	35	35	0	0	0	0	0					

Line No.	Study Area (a)	Substation (b)	Transformer (c)	Voltage (kV) (d)	Feeder (e)	SN Rating (Amps) (f)	Total Customers (g)	# Com Cust (h)	# Res Cust (i)	Amps (j)	Amps (k)	Amps (l)	Amps (m)	Amps (n)	Amps (o)	Amps (p)	Amps (q)	Amps (r)	Amps (s)	Amps (t)	Amps (u)	Amps (v)	Amps (w)	Amps (x)	2026	2035
																									Contingency Load-at-Risk (y)	Contingency Load-at-Risk (z)
72	Central RI East	APPONAUG 3	3TR	12.47	3F1	526	3376	283	3093	293.3	293.3	393.3	367.4	393.5	391	389	387	386	386	386	387	389	391	394		
73	Central RI East	APPONAUG 3	4TR	12.47	3F2	515	1783	164	1619	269.0	265.0	243.7	373.3	399.8	397	395	393	392	392	392	393	395	396	400		
74	Central RI East	DRUMROCK 14	3T12	12.47	14F1	530	2632	214	2418	339.0	333.8	431.8	326.3	361.9	359	357	356	355	355	355	356	358	360	362		
75	Central RI East	DRUMROCK 14	3T12	12.47	14F2	530	1612	248	1364	378.3	371.7	323.6	337.4	379.3	377	375	373	372	372	373	375	377	380			
76	Central RI East	DRUMROCK 14	5T12	12.47	14F3	515	237	99	138	160.0	154.3	157.1	157.0	168.1	167	232	231	230	230	231	232	234	236			
77	Central RI East	DRUMROCK 14	5T12	12.47	14F4	515	884	212	672	355.7	359.9	325.6	335.2	359.0	356	355	353	352	352	352	353	355	357	359		
78	Central RI East	KILVERT STREET 87	1TR	12.47	87F1	530	1102	323	779	339.0	354.5	308.5	284.3	328.5	326	324	323	322	322	322	323	325	327	329		
79	Central RI East	KILVERT STREET 87	2TR	12.47	87F2	570	117	76	41	270.3	289.1	264.8	243.5	303.8	302	300	299	298	298	298	299	300	302	304		
80	Central RI East	KILVERT STREET 87	1TR	12.47	87F3	530	1297	194	1103	354.0	406.7	371.2	354.1	458.2	455	453	451	449	449	449	451	453	456	459		
81	Central RI East	KILVERT STREET 87	2TR	12.47	87F4	530	221	127	94	202.0	227.2	206.2	211.2	346.2	344	342	341	340	339	340	341	342	344	347		
82	Central RI East	KILVERT STREET 87	1TR	12.47	87F5	530	1462	72	1390	299.3	303.1	279.3	286.2	306.3	304	303	301	301	300	301	302	303	305	307		
83	Central RI East	KILVERT STREET 87	2TR	12.47	87F6	530	746	341	405	216.3	225.2	220.2	228.6	244.9	383	381	240	239	239	239	240	241	242	244		
84	Central RI East	LINCOLN AVENUE 72	1TR	12.47	72F1	530	221	208	13	184.0	196.0	178.0	176.2	188.7	87	87	47	46	46	46	47	47	47	47		
85	Central RI East	LINCOLN AVENUE 72	2TR	12.47	72F2	530	2646	188	2458	349.7	351.5	316.0	329.3	373.7	371	430	428	427	427	427	429	430	433	436		
86	Central RI East	LINCOLN AVENUE 72	1TR	12.47	72F3	530	3193	138	3055	432.7	415.1	431.7	490.8	525.7	522	519	467	466	465	466	467	469	472	475		
87	Central RI East	LINCOLN AVENUE 72	2TR	12.47	72F4	530	1955	284	1691	433.0	436.3	305.2	310.9	395.0	392	390	389	387	387	387	389	390	393	395		
88	Central RI East	LINCOLN AVENUE 72	1TR	12.47	72F5	515	3379	246	3133	445.7	437.3	395.3	447.0	478.8	475	473	471	470	469	470	471	473	476	479		
89	Central RI East	LINCOLN AVENUE 72	1TR	12.47	72F6	567	2373	378	1995	513.7	544.5	481.3	477.7	478.7	366	364	272	272	271	272	272	274	275	277		
90	Central RI East	PONTIAC 27	1TR	12.47	27F1	530	1731	258	1473	353.7	344.6	379.9	375.2	401.8	399	397	362	361	361	361	362	364	366	369		
91	Central RI East	PONTIAC 27	2TR	12.47	27F2	530	3996	333	3663	458.7	456.1	425.7	435.7	466.7	463	461	259	258	258	258	259	260	262	264		
92	Central RI East	PONTIAC 27	1TR	12.47	27F3	460	20	20	0	152.3	146.9	150.1	136.0	145.6	145	144	143	143	143	143	143	144	145	146		
93	Central RI East	PONTIAC 27	2TR	12.47	27F4	460	286	232	54	298.7	270.8	274.9	370.0	306.3	393	391	290	289	289	289	290	291	293	295		
94	Central RI East	PONTIAC 27	1TR	12.47	27F5	530	3093	331	2762	455.3	447.3	410.0	413.7	443.1	440	438	436	435	434	435	436	438	441	444		
95	Central RI East	PONTIAC 27	2TR	12.47	27F6	530	66	17	50	179.3	192.2	205.2	229.1	245.4	244	242	241	241	240	241	242	243	244	246		
96	Central RI East	WARWICK 52	1TR	12.47	52F1	485	877	49	828	233.3	236.9	284.6	112.0	119.9	119	118	118	118	117	118	118	119	119	120		
97	Central RI East	WARWICK 52	1TR	12.47	52F2	485	1265	80	1185	141.3	140.5	133.8	126.1	135.1	134	133	133	132	132	132	133	134	135			
98	Central RI East	WARWICK 52	4TR	12.47	52F3	526	2699	126	2573	387.3	417.1	357.8	368.8	395.0	392	390	389	387	387	387	389	390	393	395	Borderline	Borderline
99	Central RI East	AUBURN 73	1TR	4.16	73J1	369	196	44	152	136.7	136.7	120.0	120.0	128.5	128	127	0	0	0	0	0	0	0	0		
100	Central RI East	AUBURN 73	2TR	4.16	73J2	385	264	15	249	202.7	90.7	120.0	120.0	128.5	128	127	0	0	0	0	0	0	0	0		
101	Central RI East	AUBURN 73	1TR	4.16	73J3	385	300	45	255	240.0	248.0	233.3	233.3	249.9	248	247	0	0	0	0	0	0	0	0		
102	Central RI East	AUBURN 73	2TR	4.16	73J4	385	47	26	21	240.0	140.0	183.3	232.3	297.8	296	294	0	0	0	0	0	0	0	0		
103	Central RI East	AUBURN 73	1TR	4.16	73J5	408	984	103	881	296.0	272.0	268.0	268.0	287.0	285	284	0	0	0	0	0	0	0	0		
104	Central RI East	AUBURN 73	2TR	4.16	73J6	381	444	3	441	166.7	160.0	156.0	156.0	167.1	166	165	0	0	0	0	0	0	0	0		
105	Central RI East	LAKEWOOD 57	2TR	4.16	57J1	369	596	75	521	90.7	85.0	85.0	82.3	88.2	88	87	0	0	0	0	0	0	0	0		
106	Central RI East	LAKEWOOD 57	2TR	4.16	57J2	452	624	50	574	127.0	120.3	101.7	117.7	126.0	125	124	0	0	0	0	0	0	0	0		
107	Central RI East	LAKEWOOD 57	1TR	4.16	57J3	408	1053	15	1038	172.7	168.7	146.3	161.7	173.2	172	171	0	0	0	0	0	0	0	0		
108	Central RI East	LAKEWOOD 57	1TR	4.16	57J5	492	1146	33	1113	170.3	164.3	141.7	158.3	169.6	168	168	0	0	0	0	0	0	0	0		
109	Central RI East	AUBURN 73	1TR	12.47	73F1	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	334	334	333	334	335	336	338	340		
110	Central RI East	AUBURN 73	2TR	12.47	73F2	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	311	310	309	310	311	312	314	316		
111	Central RI East	AUBURN 73	1TR	12.47	73F3	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	311	310	309	310	311	312	314	316		
112	Central RI East	AUBURN 73	2TR	12.47	73F4	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	287	286	286	286	287	288	290	292		
113	Central RI East	AUBURN 73	1TR	12.47	73F5	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	334	334	333	334	335	336	338	340		
114	Central RI East	AUBURN 73	2TR	12.47	73F6	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	334	334	333	334	335	336	338	340		
115	Central RI East	AUBURN 73	1TR	12.47	73F7	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	239	238	238	238	239	240	242	243		
116	Central RI East	AUBURN 73	2TR	12.47	73F8	550	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	239	238	238	238	239	240	242	243		
117	Central RI West	ANTHONY	1TR	12.47	64F1	361	1290	162	1128	229.7	226.7	205.7	200.7	214.9	213	212	211	211	211	211	212	212	214	215		
118	Central RI West	ANTHONY	2TR	12.47	64F2	361	964	73	891	171.3	235.7	125.7	122.3	131.0	130	129	129	129	128	129	129	130	131			
119	Central RI West	COVENTRY	1TR	12.47	54F1	526	2773	191	2582	412.7	402.3	360.1	377.2	404.0	416	414	412	411	411	411	412	414	417	419		
120	Central RI West	DIVISION ST	1TR	12.47	61F1	450	295	24	271	321.0	345.7	312.1	297.4	318.6	409	407	405	404	403	404	405	407	409	412		
121	Central RI West	DIVISION ST	2TR	12.47	61F2	450	1499	144	1355	287.7	294.0	280.1	306.0	327.8	337	336	334	333	333	334	336	338	340			
122	Central RI West	DIVISION ST	1TR	12.47	61F3	450	1016	176	840	375.0	355.3	348.8	331.9	355.5	353	351	350	349	348	349	350	351	354	356		
123	Central RI West	DIVISION ST	2TR	12.47	61F4	450	1175	204	971	328.7	327.3	318.3	354.1	379.3	420	418	416	415	415	415	417	418	421	424		
124	Central RI West	HOPE	1TR	12.47	15F1	348	1178	43	1135	157.3	153.3	141.7	132.3	227.4	226	225	224	223	223	223	224	225	226	228		
125	Central RI West	HOPE	1TR	12.47	15F2	515	2493	94	2399	398.0	379.7	351.7	375.1	401.8</												

Line No.	Study Area (a)	Substation (b)	Transformer (c)	Voltage (kV) (d)	Feeder (e)	SN Rating (Amps) (f)	Total Customers (g)	# Com Cust (h)	# Res Cust (i)	Amps (j)	Amps (k)	Amps (l)	Amps (m)	Amps (n)	Amps (o)	Amps (p)	Amps (q)	Amps (r)	Amps (s)	Amps (t)	Amps (u)	Amps (v)	Amps (w)	Amps (x)	2026	2035
																									Contingency Load-at-Risk (y)	Contingency Load-at-Risk (z)
144	Central RI West	NEW LONDON AVE	2TR	12.47	150F6	535	3666	371	3295	406.0	397.7	376.0	174.2	186.6	185	184	184	183	183	183	184	184	186	187		
145	Central RI West	NEW LONDON AVE	2TR	12.47	150F8	535	2544	162	2382	259.3	261.3	271.6	453.4	485.6	482	480	478	476	476	476	478	480	483	486		
146	East Bay	BARRINGTON 4	1TR	12.47	4F1	515	2370	218	2152	391.7	390.0	349.7	376.0	402.0	376	0	0	0	0	0	0	0	0	0	Yes	
147	East Bay	BARRINGTON 4	1TR	12.47	4F2	510	3073	231	2842	464.3	440.0	395.0	406.0	435.0	406	0	0	0	0	0	0	0	0	0	Yes	
148	East Bay	BRISTOL 51A	1TR	12.47	51F1	645	2126	204	1922	412.7	421.0	403.0	365.0	391.0	388	387	301	303	304	305	306	307	311	314		
149	East Bay	BRISTOL 51A	2TR	12.47	51F2	530	3768	370	3398	449.0	427.0	439.0	432.0	463.0	459	458	307	308	309	310	312	313	316	319	Yes	
150	East Bay	BRISTOL 51A	1TR	12.47	51F3	502	2173	438	1735	332.0	364.0	335.0	335.0	359.0	356	356	320	321	323	324	325	327	330	333		
151	East Bay	PHILLIPSDALE 20	3TR	12.47	20F1	425	890	148	742	271.3	313.0	260.0	264.0	282.0	280	280	0	0	0	0	0	0	0	0	Yes	
152	East Bay	PHILLIPSDALE 20	3TR	12.47	20F2	425	1913	127	1786	343.7	325.0	274.0	267.0	286.0	284	284	0	0	0	0	0	0	0	0		
153	East Bay	WAMPANOAG 48	1TR	12.47	48F1	502	4261	581	3680	476.0	470.0	421.0	432.0	463.0	459	495	292	293	294	295	296	297	300	303	Borderline	
154	East Bay	WAMPANOAG 48	2TR	12.47	48F2	515	493	221	272	331.9	360.0	360.0	312.0	334.0	332	345	345	346	347	349	350	352	355	359	Borderline	
155	East Bay	WAMPANOAG 48	1TR	12.47	48F3	510	3540	388	3152	413.5	400.0	424.0	360.0	386.0	383	267	267	268	269	270	271	272	275	278		
156	East Bay	WAMPANOAG 48	2TR	12.47	48F4	530	2083	250	1833	403.4	430.0	382.0	375.0	402.0	399	420	419	421	423	424	426	428	432	436	Yes	
157	East Bay	WAMPANOAG 48	1TR	12.47	48F5	530	3093	209	2884	337.4	404.0	393.0	393.0	421.0	418	300	300	301	302	303	305	306	309	312	Yes	
158	East Bay	WAMPANOAG 48	2TR	12.47	48F6	530	1768	306	1462	301.8	430.0	398.0	437.0	468.0	465	445	445	446	448	450	452	454	458	463	Yes	
159	East Bay	WARREN 5	1TR	12.47	5F1	425	2096	133	1963	351.3	350.0	335.0	347.0	372.0	369	302	301	303	304	305	306	308	311	314	Yes	
160	East Bay	WARREN 5	2TR	12.47	5F2	434	2582	313	2269	346.3	398.0	330.0	334.0	358.0	355	284	283	285	286	287	288	289	292	295	Borderline	
161	East Bay	WARREN 5	1TR	12.47	5F3	530	2547	298	2249	350.7	327.0	302.0	310.0	332.0	330	332	332	333	335	336	337	339	342	345		
162	East Bay	WARREN 5	2TR	12.47	5F4	510	3648	315	3333	420.7	400.0	427.0	413.0	442.0	439	438	438	439	441	443	445	447	451	456		
163	East Bay	WATERMAN AVENUE 78	1TR	12.47	78F3	409	1311	1136	1136	236.0	248.0	308.0	344.0	368.0	366	0	0	0	0	0	0	0	0	0	Borderline	
164	East Bay	WATERMAN AVENUE 78	2TR	12.47	78F4	409	1035	162	873	191.7	186.0	237.0	256.0	274.0	272	0	0	0	0	0	0	0	0	0	Borderline	
165	East Bay	KENT CORNERS 47	2TR	4.16	47I2	408	819	45	774	284.0	248.0	150.0	300.0	321.0	319	0	0	0	0	0	0	0	0	0		
166	East Bay	KENT CORNERS 47	1TR	4.16	47I3	408	767	25	742	292.0	300.0	224.0	272.0	291.0	289	0	0	0	0	0	0	0	0	0		
167	East Bay	KENT CORNERS 47	2TR	4.16	47I4	408	871	37	834	276.0	305.0	256.0	280.0	300.0	298	0	0	0	0	0	0	0	0	0		
168	East Bay	EAST PROVIDENCE SUB	1TR	12.47	F1	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	382	382	383	385	386	388	389	393	397		
169	East Bay	EAST PROVIDENCE SUB	2TR	12.47	F2	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	285	285	286	287	288	289	290	293	296		
170	East Bay	EAST PROVIDENCE SUB	1TR	12.47	F3	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	348	191	192	193	193	194	195	197	199		
171	East Bay	EAST PROVIDENCE SUB	2TR	12.47	F4	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	461	391	393	395	396	398	399	403	407		
172	East Bay	WARREN 5	1TR	12.47	5F5	500	0	0	0	0.0	0.0	0.0	0.0	0.0	0	330	329	331	332	333	335	336	339	343		
173	East Bay	WARREN 5	2TR	12.47	5F6	500	0	0	0	0.0	0.0	0.0	0.0	0.0	0	439	439	440	442	444	446	447	452	456		
174	East Bay	PHILLIPSDALE 20	1TR	12.47	F1	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	429	431	432	434	436	438	442	446		
175	East Bay	PHILLIPSDALE 20	1TR	12.47	F3	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	426	428	429	431	433	435	439	443		
176	East Bay	PHILLIPSDALE 20	4TR	12.47	F5	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	295	296	297	299	300	301	304	307		
177	East Bay	PHILLIPSDALE 20	4TR	12.47	F7	530	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	184	185	185	186	187	188	190	191		
178	East Bay	BRISTOL 51A	2TR	12.47	51F4	500	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	272	273	274	275	276	278	280	283		
179	Newport	DEXTER	364	13.8	36W41	464	2111	258	1853	248.0	253.3	234.7	250.5	268.0	266	265	264	263	263	264	265	267	269	273		
180	Newport	DEXTER	364	13.8	36W42	464	2160	115	2045	219.7	238.3	198.7	217.8	233.0	232	230	229	229	229	229	229	231	232	234		
181	Newport	DEXTER	364	13.8	36W43	464	1782	239	1543	225.7	219.0	211.0	221.8	238.0	236	235	234	233	233	233	234	235	237	238		
182	Newport	DEXTER	364	13.8	36W44	464	1961	275	1686	255.0	255.3	251.7	213.3	228.0	227	226	225	224	224	224	225	226	228	229		
183	Newport	JEPSON	5TR	13.8	37W1	480	716	84	632	260.0	257.0	87.7	86.3	92.0	92	91	91	91	91	91	91	91	92	93		
184	Newport	JEPSON	6TR	13.8	37W2	480	161	20	141	285.3	157.7	139.7	137.7	147.0	146	146	145	145	144	145	145	146	147	148		
185	Newport	JEPSON	5TR	13.8	37W3	480	2249	215	2034	262.0	255.7	241.7	241.8	259.0	257	256	255	254	254	254	255	256	258	259		
186	Newport	CLARKE STREET	651	4.16	65I2	570	1032	179	853	376.0	287.0	297.7	297.7	319.0	317	315	314	313	312	313	314	315	317	319		
187	Newport	CLARKE STREET	12TR	4.16	65I12	575	760	72	688	358.7	350.3	333.0	315.0	337.0	335	333	332	331	331	331	332	334	336	338		
188	Newport	ELDRED	1TR	4.16	45J3	560	1205	33	1172	519.3	509.0	456.7	470.3	504.0	500	498	496	494	494	494	496	498	502	505		
189	Newport	ELDRED	2TR	4.16	45J4	560	420	39	381	248.0	248.3	237.0	237.0	254.0	252	251	250	249	249	249	250	251	253	254		
190	Newport	HARRISON	321	4.16	32I2	360	604	53	551	279.3	284.7	295.3	278.0	298.0	296	294	293	292	292	292	293	294	296	298		
191	Newport	HARRISON	321	4.16	32I4	300	468	20	448	159.0	155.0	159.0	154.5	165.0	164	163	163	162	162	162	163	164	165	166		
192	Newport	HARRISON	322	4.16	32I12	405	452	83	369	358.3	391.7	387.7	373.0	399.0	397	395	393	392	391	392	393	395	398	400		
193	Newport	HARRISON	322	4.16	32I14	410	545	43	502	330.7	336.3	327.7	337.3	361.0	359	357	355	354	354	354	355	357	360	362		
194	Newport	HOSPITAL	461	4.16	146I2	300	565	52	513	168.3	160.7	159.0	197.5	211.0	210	209	208	207	207	207	208	209	211	212		
195	Newport	HOSPITAL	461	4.16	146I4	434	0.5	0.5	0	232.7	234.3	236.7	228.7	245.0	243	242	241	240	240	241	242	244	244	245		
196	Newport	HOSPITAL	462	4.16	146I12	434	0.5	0.5	0	142.3	142.3	138.7	134.7	144.0	143	142	142	141	141	141	142	143	144	144		
197	Newport	HOSPITAL	462	4.16	146I14	307	581	84	497	148.3	149.7	149.7	149.7	160.0	159	158	158	157	157	157	158	159	160</			

Line No.	Study Area (a)	Substation (b)	Transformer (c)	Voltage (kV) (d)	Feeder (e)	SN Rating (Amps) (f)	Total Customers (g)	# Com Cust (h)	# Res Cust (i)	Amps (j)	Amps (k)	Amps (l)	Amps (m)	Amps (n)	Amps (o)	Amps (p)	Amps (q)	Amps (r)	Amps (s)	Amps (t)	Amps (u)	Amps (v)	Amps (w)	Amps (x)	2026	2035	
																									Contingency Load-at-Risk (y)	Contingency Load-at-Risk (z)	
216	Newport	NEWPORT SUB	1TR	13.8	203W5	520	2009	216	1793	191.7	217.7	188.7	185.1	198.0	197	196	195	194	194	194	195	196	197	199			
217	Newport	NEWPORT SUB	1TR	13.8	203W7	520	2449	326	2123	219.3	250.0	215.7	216.2	231.0	230	229	228	227	227	228	229	231	232				
218	Newport	JEPSON	6TR	13.8	37W4	530	1489	317	1172	359.7	264.7	261.3	257.0	275.0	273	272	271	270	270	270	271	272	274	276			
219	Newport	JEPSON	5TR	13.8	37W5	525	1903	342	1561	238.7	346.7	252.7	263.3	282.0	280	279	277	277	276	277	277	279	281	283			
220	Newport	JEPSON	6TR	13.8	37W6	480	1643	235	1408	271.3	256.3	247.0	240.0	257.0	255	254	253	252	252	252	253	254	256	257			
221	North Central RI	CENTREDALE 50	2TR	12.47	50F1	367	0	0	0	0.0	0.0	0.0	0.0	0.0	0	0	137	137	136	137	137	138	139				
222	North Central RI	CENTREDALE 50	3TR	12.47	50F2	367	2143	219	1924	300.0	272.0	264.0	263.3	282.0	280	279	278	277	277	278	279	281	283				
223	North Central RI	CHOPMIST 34	1TR	12.47	34F1	530	3444	286	3158	458.3	450.6	402.9	444.4	476.0	472	470	468	467	466	467	468	470	473	477			
224	North Central RI	CHOPMIST 34	2TR	12.47	34F2	415	2720	261	2459	340.7	331.8	308.2	340.5	364.7	362	360	359	358	357	358	359	360	363	365			
225	North Central RI	CHOPMIST 34	3TR	12.47	34F3	585	866	62	804	212.3	213.0	222.5	210.0	204.1	203	202	201	200	200	200	201	202	203	204	Yes	Yes	
226	North Central RI	FARNUM PIKE 23	1TR	12.47	23F1	530	1555	117	1438	282.0	273.5	249.5	256.3	274.5	273	271	270	269	269	269	270	271	273	275			
227	North Central RI	FARNUM PIKE 23	2TR	12.47	23F2	515	1126	210	916	366.0	363.8	316.5	304.0	325.6	323	322	320	319	319	319	320	322	324	326			
228	North Central RI	FARNUM PIKE 23	1TR	12.47	23F3	530	1526	181	1345	448.3	449.8	389.5	351.9	376.9	374	372	371	370	369	370	371	372	375	377			
229	North Central RI	FARNUM PIKE 23	2TR	12.47	23F4	530	263	67	196	157.7	172.2	144.8	149.3	159.9	159	158	157	157	157	157	157	158	159	160			
230	North Central RI	FARNUM PIKE 23	1TR	12.47	23F5	515	29	23	6	96.0	107.5	108.5	106.3	59.7	59	59	59	58	59	59	59	59	59	60			
231	North Central RI	FARNUM PIKE 23	2TR	12.47	23F6	515	3009	184	2845	356.7	357.2	330.5	339.8	364.0	361	360	358	357	357	357	358	360	362	364			
232	North Central RI	JOHNSTON 18	3T12	12.47	18F5	530	5002	628	4373	415.3	462.3	488.4	528.5	532.0	465	463	461	459	459	459	461	463	466	469			
233	North Central RI	JOHNSTON 18	4T12	12.47	18F6	515	1590	352	1238	319.3	369.3	413.6	412.9	306.5	304	303	301	301	300	301	302	303	305	307			
234	North Central RI	JOHNSTON 18	3T12	12.47	18F7	530	3256	306	2950	363.3	347.8	394.0	489.1	414.8	412	410	408	407	406	407	408	410	413	415	Yes		
235	North Central RI	JOHNSTON 18	4T12	12.47	18F8	530	1772	233	1539	269.3	283.3	248.6	258.6	277.0	275	274	272	272	271	272	273	274	276	277			
236	North Central RI	JOHNSTON 18	3T12	12.47	18F9	530	3387	466	2921	403.0	528.7	466.3	506.9	570.3	507	504	502	501	500	501	502	504	508	511			
237	North Central RI	JOHNSTON 18	4T12	12.47	18F10	531	2892	282	393.3	373.1	425.9	417.2	433.5	430	405	222	221	221	221	222	223	224	226		Yes		
238	North Central RI	JOHNSTON 18	3T12	12.47	18F11	526	2227	341	1886	373.3	331.5	314.6	255.8	440.8	438	435	434	432	432	432	434	436	438	441	Yes	Borderline	Yes
239	North Central RI	JOHNSTON 18	4T12	12.47	18F12	507	28	0	28	160.7	125.5	121.6	109.4	117.2	116	116	115	115	115	115	115	116	117	117			
240	North Central RI	JOHNSTON 18	3T12	12.47	18F13	460	2040	341	1699	353.0	373.8	344.5	341.6	318.1	316	314	313	312	312	312	313	314	316	318	Yes	Borderline	
241	North Central RI	JOHNSTON 18	4T12	12.47	18F14	515	537	316	221	170.3	164.6	202.3	205.4	220.0	218	217	216	216	216	217	217	219	220				
242	North Central RI	MANTON 69	1TR	12.47	69F1	515	3731	301	3430	424.0	438.0	400.0	406.7	435.6	432	430	428	427	427	427	429	430	433	436			
243	North Central RI	MANTON 69	1TR	12.47	69F3	502	4852	326	4526	473.0	473.0	452.0	452.0	484.1	481	478	476	475	474	475	476	478	482	485	Yes	Yes	
244	North Central RI	PUTNAM PIKE 38	1TR	12.47	38F1	530	2735	252	2483	482.7	470.7	393.7	379.5	405.5	403	402	400	399	398	399	400	402	404	407			
245	North Central RI	PUTNAM PIKE 38	2TR	12.47	38F2	530	1283	744	539	185.7	197.3	291.3	299.7	321.0	319	317	316	315	315	315	316	317	319	321			
246	North Central RI	PUTNAM PIKE 38	1TR	12.47	38F3	530	1397	90	1307	312.3	325.0	293.9	290.9	311.6	309	308	306	306	305	306	307	308	310	312			
247	North Central RI	PUTNAM PIKE 38	2TR	12.47	38F4	515	2546	243	2303	352.0	362.0	316.9	329.0	352.4	350	348	348	347	347	347	349	350	352	355			
248	North Central RI	PUTNAM PIKE 38	1TR	12.47	38F5	395	1711	94	1617	241.7	248.5	231.4	235.4	252.1	250	249	248	247	247	247	248	249	251	252			
249	North Central RI	PUTNAM PIKE 38	2TR	12.47	38F6	530	2834	275	2559	416.0	426.5	389.0	390.6	418.3	415	413	411	410	410	410	412	413	416	419			
250	North Central RI	WEST CRANSTON 21	1TR	12.47	21F1	515	2647	61	2586	462.7	461.3	414.9	422.5	452.5	449	447	445	444	443	444	445	447	450	453	Yes	Yes	
251	North Central RI	WEST CRANSTON 21	2TR	12.47	21F2	515	1262	324	938	404.3	421.3	328.9	377.5	404.3	401	399	398	397	396	397	398	400	402	405	Yes	Yes	
252	North Central RI	WEST CRANSTON 21	2TR	12.47	21F4	515	2282	173	2109	424.3	424.1	391.8	396.7	472.6	469	467	465	464	463	464	465	467	470	473	Yes	Yes	
253	North Central RI	WEST GREENVILLE 45	3TR	12.47	45F2	425	1611	159	1452	352.3	284.0	292.3	261.0	279.5	277	276	275	274	274	274	275	276	278	280			
254	North Central RI	CENTREDALE 50	1TR	4.16	50I1	285	447	28	419	104.0	133.3	160.0	160.0	171.4	170	169	0	0	0	0	0	0	0	0			
255	North Central RI	CENTREDALE 50	1TR	4.16	50J3	408	616	72	544	181.3	276.7	232.0	220.0	235.6	234	233	0	0	0	0	0	0	0	0			
256	Providence	CLARKSON STREET 13	1TR	12.47	13F1	400	210	16	194	244.7	261.0	257.0	252.7	270.7	269	268	268	269	270	271	272	273	276	279			
257	Providence	CLARKSON STREET 13	2TR	12.47	13F2	540	219	419	2362	285.7	337.0	292.0	323.9	421.9	134	134	133	134	134	135	136	136	137	139			
258	Providence	CLARKSON STREET 13	1TR	12.47	13F3	425	1054	242	812	306.0	407.0	411.0	385.1	412.4	253	310	310	311	312	313	315	316	319	322			
259	Providence	CLARKSON STREET 13	2TR	12.47	13F4	520	3861	230	3531	464.7	443.0	419.0	422.2	452.2	449	448	447	449	451	453	455	457	461	466			
260	Providence	CLARKSON STREET 13	1TR	12.47	13F5	455	3935	403	3532	396.3	408.0	377.0	417.8	446.4	443	442	442	444	445	447	449	451	455	460			
261	Providence	CLARKSON STREET 13	2TR	12.47	13F6	415	233	27	206	269.3	185.0	285.0	276.4	190.0	189	188	188	189	190	190	191	192	194	196			
262	Providence	CLARKSON STREET 13	1TR	12.47	13F7	436	334	15	319	126.0	198.0	230.0	184.1	197.1	196	195	195	196	197	197	198	199	201	203			
263	Providence	CLARKSON STREET 13	2TR	12.47	13F8	437	5	5	0	191.0	258.0	275.0	171.6	183.8	182	182	182	183	183	184	185	186	187	189			
264	Providence	CLARKSON STREET 13	1TR	12.47	13F9	530	4341	405	3936	453.7	478.0	467.0	449.6	481.5	118	278	277	279	280	281	282	283	286	289			
265	Providence	CLARKSON STREET 13	2TR	12.47	13F10	530	2415	293	2122	261.3	332.0	362.0	320.7	343.5	341	340	340	341	343	344	345	347	350	354			
266	Providence	ELMWOOD 7 - OUTDOOR	2TR	12.47	7F1	530	2850	300	2550	364.7	369.0	321.0	332.8	356.4	354	353	353	354	356	357	358	360	363	367			
267	Providence	ELMWOOD 7 - OUTDOOR	2TR	12.47	7F2	530	2008	275	1733	339.7	367.0	339.0	338.7	362.7	360	359	359	360	362								

Line No.	Study Area (a)	Substation (b)	Transformer (c)	Voltage (kV) (d)	Feeder (e)	SN Rating (Amps) (f)	Total Customers (g)	# Com Cust (h)	# Res Cust (i)	Amps (j)	Amps (k)	Amps (l)	Amps (m)	Amps (n)	Amps (o)	Amps (p)	Amps (q)	Amps (r)	Amps (s)	Amps (t)	Amps (u)	Amps (v)	Amps (w)	Amps (x)	2026	2035	
																									Contingency Load-at-Risk (y)	Contingency Load-at-Risk (z)	
288	Providence	FRANKLIN SQUARE 11	Network	11.5	1149	330	227	227	0	111.0	111.0	111.0	273.0	292.4	290	290	289	291	292	293	294	295	298	301			
289	Providence	FRANKLIN SQUARE 11	Network	11.5	1153	313	0	0	0	131.3	136.0	172.0	141.3	151.3	150	150	150	150	151	152	152	153	154	156			
290	Providence	HARRIS AVENUE 12	Network	11.5	1129	290	1	1	0	100.0	80.0	44.0	98.7	105.7	105	0	0	0	0	0	0	0	0	0			
291	Providence	HARRIS AVENUE 12	Network	11.5	1131	290	78	78	0	63.3	65.0	80.0	72.7	77.8	77	0	0	0	0	0	0	0	0	0			
292	Providence	HARRIS AVENUE 12	Network	11.5	1133	290	182	182	0	90.0	90.0	60.0	80.0	85.7	85	0	0	0	0	0	0	0	0	0			
293	Providence	HARRIS AVENUE 12	Network	11.5	1137	290	0	0	0	208.0	170.0	195.0	194.7	208.5	207	0	0	0	0	0	0	0	0	0			
294	Providence	HARRIS AVENUE 12	Network	11.5	1145	221	0	0	0	80.0	80.0	85.0	88.0	94.3	94	0	0	0	0	0	0	0	0	0			
295	Providence	HARRIS AVENUE 12	Network	11.5	1147	290	19	19	0	40.0	40.0	80.0	36.7	39.3	39	0	0	0	0	0	0	0	0	0			
296	Providence	SOUTH STREET 1	Network	11.5	1101	292	573	573	0	146.7	156.0	168.0	172.6	184.9	184	183	183	184	184	185	186	187	189	190			
297	Providence	SOUTH STREET 1	Network	11.5	1111	450	188	188	0	222.3	237.0	207.0	177.6	190.2	189	188	188	189	190	191	191	192	194	196			
298	Providence	SOUTH STREET 1	Network	11.5	1113	450	62	62	0	224.7	231.0	228.0	185.2	198.3	197	196	196	197	198	199	199	200	202	204			
299	Providence	SOUTH STREET 1	Network	11.5	1127	450	151	151	0	203.0	212.0	191.0	172.3	184.6	183	183	183	183	184	185	186	186	188	190			
300	Providence	SOUTH STREET 1	Network	11.5	1135	450	18	18	0	205.3	208.0	198.0	171.8	184.0	183	182	182	183	184	184	185	186	188	190			
301	Providence	SOUTH STREET 1	Network	11.5	1151	322	0	0	0	236.3	240.0	264.0	287.4	307.8	306	305	305	306	307	308	310	311	314	317			
302	Providence	SOUTH STREET 1	Network	11.5	1152	326	0	0	0	196.3	195.0	260.0	208.4	223.2	222	221	221	222	223	224	224	225	228	230			
303	Providence	SOUTH STREET 1	Network	11.5	1169	350	270	270	0	195.7	197.0	207.0	216.9	232.3	231	230	230	231	232	233	234	234	237	239			
304	Providence	SOUTH STREET 1	Network	11.5	1171	326	271	271	0	66.0	71.0	157.0	101.0	108.2	107	107	107	108	108	109	109	110	111	111			
305	Providence	EAST GEORGE ST 77	1TR	4.16	7711	371	967	181	786	336.7	317.0	280.0	336.7	360.6	358	357	357	358	360	361	363	364	368	371			
306	Providence	EAST GEORGE ST 77	2TR	4.16	7712	364	1026	104	922	318.3	287.0	274.0	280.0	299.9	298	297	297	298	299	300	302	303	306	309			
307	Providence	EAST GEORGE ST 77	1TR	4.16	7713	371	1410	190	1220	350.0	267.0	290.0	286.7	307.0	305	304	304	305	306	308	309	310	313	316			
308	Providence	EAST GEORGE ST 77	2TR	4.16	7714	364	583	173	410	300.0	267.0	277.0	255.0	273.1	271	271	270	271	272	274	275	276	278	281			
309	Providence	GENEVA 71	1TR	4.16	7111	274	664	473	664	204.0	216.0	204.0	228.7	244.9	243	0	0	0	0	0	0	0	0	0			
310	Providence	GENEVA 71	1TR	4.16	7112	274	202	1	201	120.0	96.0	63.0	60.0	64.3	64	0	0	0	0	0	0	0	0	0			
311	Providence	GENEVA 71	2TR	4.16	7113	274	545	58	487	176.0	176.0	170.0	166.0	177.8	176	0	0	0	0	0	0	0	0	0			
312	Providence	GENEVA 71	2TR	4.16	7114	274	588	45	543	210.0	176.0	144.0	151.3	162.1	161	0	0	0	0	0	0	0	0	0			
313	Providence	GENEVA 71	2TR	4.16	7115	408	1350	83	1267	304.0	312.0	256.0	288.0	308.5	306	17	17	17	17	17	17	17	17	17			
314	Providence	HARRIS AVENUE 12	1TR	4.16	1211	425	466	57	409	103.3	103.3	110.0	113.3	121.4	120	0	0	0	0	0	0	0	0	0			
315	Providence	HARRIS AVENUE 12	2TR	4.16	1212	425	728	184	564	210.0	240.0	237.0	236.7	253.5	252	0	0	0	0	0	0	0	0	0			
316	Providence	HARRIS AVENUE 12	1TR	4.16	1213	425	0	0	0	0.0	0.0	0.0	60.0	64.3	64	0	0	0	0	0	0	0	0	0			
317	Providence	HARRIS AVENUE 12	2TR	4.16	1214	425	1280	193	1087	320.0	314.0	344.0	310.0	332.0	330	0	0	0	0	0	0	0	0	0			
318	Providence	HARRIS AVENUE 12	1TR	4.16	1215	340	40	34	6	100.0	110.0	110.0	100.0	107.1	106	0	0	0	0	0	0	0	0	0			
319	Providence	HARRIS AVENUE 12	2TR	4.16	1216	408	46	46	0	156.7	156.7	100.0	100.0	107.1	106	0	0	0	0	0	0	0	0	0			
320	Providence	HUNTINGTON PARK 67	1TR	4.16	6711	274	150	58	92	238.0	233.0	214.0	215.7	231.0	229	229	229	230	230	231	232	233	236	238			
321	Providence	KNIGHTSVILLE 66	1TR	12.47	66F1	530	2958	0	2958	0.0	0.0	0.0	101.5	108.7	108	108	108	108	108	109	109	110	111	112			
322	Providence	OLNEYVILLE 6	1TR/2TR	4.16	612	306	1064	123	941	245.3	240.0	248.0	226.7	242.8	241	240	240	241	242	243	244	245	248	250			
323	Providence	OLNEYVILLE 6	1TR/2TR	4.16	616	306	80	50	30	96.0	110.0	120.0	60.0	65.0	64	0	0	0	0	0	0	0	0	0			
324	Providence	OLNEYVILLE 6	1TR/2TR	4.16	618	306	511	56	455	109.3	80.0	181.0	122.7	131.4	130	8	8	8	8	8	8	8	8	8			
325	Providence	ROCHAMBEAU AVENUE 37	2TR	4.16	3711	329	414	95	319	140.0	80.0	100.0	100.0	107.1	106	0	0	0	0	0	0	0	0	0			
326	Providence	ROCHAMBEAU AVENUE 37	1TR	4.16	3712	380	583	30	553	226.0	224.0	196.0	196.0	209.9	208	0	0	0	0	0	0	0	0	0			
327	Providence	ROCHAMBEAU AVENUE 37	2TR	4.16	3713	303	858	63	795	260.0	250.0	222.0	243.3	260.6	259	0	0	0	0	0	0	0	0	0			
328	Providence	ROCHAMBEAU AVENUE 37	1TR	4.16	3714	380	904	110	794	236.7	236.0	220.0	231.7	248.1	246	0	0	0	0	0	0	0	0	0			
329	Providence	ROCHAMBEAU AVENUE 37	2TR	4.16	3715	347	842	92	750	284.0	264.0	245.0	272.0	291.3	289	0	0	0	0	0	0	0	0	0			
330	Providence	SPRAGUE STREET 36	1TR	4.16	3611	236	769	96	673	163.3	190.0	215.0	203.3	217.8	216	216	216	216	217	218	219	220	222	224			
331	Providence	SPRAGUE STREET 36	2TR	4.16	3612	252	807	113	694	200.0	200.0	215.0	205.0	219.6	218	218	217	218	219	220	221	222	224	226			
332	Providence	SPRAGUE STREET 36	2TR	4.16	3614	344	507	129	378	206.7	203.0	195.0	170.0	182.1	181	180	180	181	182	182	183	184	186	188			
333	Providence	SPRAGUE STREET 36	1TR	4.16	3615	315	934	112	822	270.0	277.0	274.0	263.3	282.0	280	279	279	280	281	282	284	285	288	290			
334	Providence	ADMIRAL STREET 9	1TR	12.47	9F1	530	0	0	0	0.0	0.0	0.0	0.0	0.0	300	299	299	300	301	303	304	305	308	311			
335	Providence	ADMIRAL STREET 9	2TR	12.47	9F2	530	0	0	0	0.0	0.0	0.0	0.0	0.0	396	465	465	466	467	468	470	472	474	479	484		
336	Providence	ADMIRAL STREET 9	1TR	12.47	9F3	530	0	0	0	0.0	0.0	0.0	0.0	0.0	227	427	426	428	430	431	433	435	439	443			
337	Providence	ADMIRAL STREET 9	2TR	12.47	9F4	530	0	0	0	0.0	0.0	0.0	0.0	0.0	166	511	510	512	514	516	518	520	526	531			
338	Providence	ADMIRAL STREET 9	1TR	12.47	9F5	530	0	0	0	0.0	0.0	0.0	0.0	0.0	80	410	409	411	413	414	416	418	422	426			
339	Providence	ADMIRAL STREET 9	2TR	12.47	9F6	530	0	0	0	0.0	0.0	0.0	0.0	0.0	65	115	115	115	116	116	117	117	118	119			
340	Providence	SOUTH ST 4KV	1TR	4.16	111	320	1175	0	1175	0.0	0.0	0.0	278.6	298.4	296	296	295	296	298	299	300	301	304	307			
341	Providence	SOUTH ST 4KV	2TR	4.16	112	320	352	0	352	0.0	0.0	0.0	202.3	216.7	215	215	214	215	216	217	218	219	221	223			
342	Providence	SOUTH ST 4KV	1TR	4.16	113	320	161	0	161	0.0	0.0	0.0	136.2	145.8	145	144	144	145	145	146	147	147	149	150			
343	Providence	SOUTH ST 4KV	2TR																								

Line No.	Study Area (a)	Substation (b)	Transformer (c)	Voltage (kV) (d)	Feeder (e)	SN Rating (Amps) (f)	Total Customers (g)	# Com Cust (h)	# Res Cust (i)	Amps (j)	Amps (k)	Amps (l)	Amps (m)	Amps (n)	Amps (o)	Amps (p)	Amps (q)	Amps (r)	Amps (s)	Amps (t)	Amps (u)	Amps (v)	Amps (w)	Amps (x)	2026	2035
																									Contingency Load-at-Risk (y)	Contingency Load-at-Risk (z)
360	South County East	PEACEDALE 59	2TR	12.47	59F2	492	2648	324	2324	271.7	279.7	259.7	276.0	299.0	298	299	298	299	301	302	303	304	308	312		
361	South County East	PEACEDALE 59	1TR	12.47	59F3	492	2917	220	2697	418.3	414.3	389.0	395.0	312.0	312	312	312	313	314	316	317	318	322	326		
362	South County East	PEACEDALE 59	2TR	12.47	59F4	425	1101	165	936	159.3	171.3	167.0	161.7	175.0	175	175	175	176	177	177	178	180	183			
363	South County East	QUONSET 83	1TR	12.47	83F1	555	8	8	0	109.7	112.7	135.0	138.7	150.0	150	150	150	151	152	152	153	155	157			
364	South County East	QUONSET 83	2TR	12.47	83F2	555	217	211	6	354.7	372.7	355.7	376.0	407.0	406	407	406	408	410	411	413	414	419	424		
365	South County East	QUONSET 83	1TR	12.47	83F3	515	4	3	1	268.7	275.7	277.0	283.0	306.0	306	306	306	307	308	309	311	312	316	319		
366	South County East	WAKEFIELD 17	3TR	12.47	17F1	602	2887	240	2647	408.3	429.3	434.0	395.3	428.0	427	428	427	429	431	432	434	436	441	446	Yes	
367	South County East	WAKEFIELD 17	4TR	12.47	17F2	515	2862	287	2575	451.3	465.0	457.0	432.3	468.0	467	468	467	469	471	473	475	477	482	488	Yes	
368	South County East	WAKEFIELD 17	5TR	12.47	17F3	597	1999	322	1677	468.0	433.0	416.7	422.7	457.0	457	457	457	459	460	462	464	466	472	477		
369	South County East	TOWER HILL 88	1TR	12.47	88F1	530	2345	340	2005	381.0	403.7	396.7	341.7	370.0	369	370	369	371	372	374	375	377	381	386		
370	South County East	TOWER HILL 88	1TR	12.47	88F3	550	2335	250	2085	377.7	378.0	403.3	360.0	390.0	389	389	389	391	392	394	395	397	402	406		
371	South County East	TOWER HILL 88	1TR	12.47	88F5	530	2270	166	2104	380.0	369.3	325.0	348.7	377.0	377	377	377	378	380	381	383	384	389	394		
372	South County East	TOWER HILL 88	1TR	12.47	88F7	530	2228	351	1877	345.0	343.3	335.0	328.7	355.0	355	355	355	357	358	359	361	362	367	371		
373	South County East	QUONSET 83	2TR	12.47	83F4	515	2003	161	1842	241.0	252.3	229.3	240.0	104.0	104	260	259	260	261	261	262	262	262	262		
374	South County East	WICKFORD JCT 89	10TR	34.5	89T1	50	1	1	0	0.0	0.0	623.0	623.0	623.0	623	623	623	623	623	623	623	623	623	623		
375	South County East	LAFAYETTE 30	1TR	12.47	89F1	530	0	0	0	0.0	0.0	0.0	0.0	0.0	350	350	350	351	352	354	355	357	361	365		
376	South County East	LAFAYETTE 30	2TR	12.47	89F2	530	0	0	0	0.0	0.0	0.0	0.0	0.0	265	265	265	266	267	268	269	270	273	277		
377	South County East	LAFAYETTE 30	1TR	12.47	89F3	530	0	0	0	0.0	0.0	0.0	0.0	0.0	169	170	169	170	171	172	172	173	175	177		
378	South County East	LAFAYETTE 30	2TR	12.47	89F4	530	0	0	0	0.0	0.0	0.0	0.0	0.0	275	276	275	276	278	279	280	281	284	288		
379	South County West	KENYON 68	1TR	12.47	68F1	512	2724	255	2469	290.0	357.3	323.7	316.9	334.3	332	330	329	328	328	328	329	330	333	335		
380	South County West	KENYON 68	2TR	12.47	68F2	511	4557	245	4312	445.0	464.0	457.7	432.6	421.7	419	417	415	414	413	414	415	417	419	422	Yes	
381	South County West	KENYON 68	1TR	12.47	68F3	512	3237	240	2997	373.0	376.0	340.7	367.8	393.9	391	389	388	386	386	388	389	392	394			
382	South County West	KENYON 68	2TR	12.47	68F4	514	2607	285	2322	370.0	397.3	403.3	377.9	387.8	385	383	381	380	380	380	382	383	386	388		
383	South County West	KENYON 68	1TR	12.47	68F5	612	89	55	34	165.0	147.3	147.7	140.9	197.7	196	195	195	194	194	194	195	195	197	198		
384	South County West	LANGWORTHY 86	1TR	12.47	86F1	600	2782	194	2588	442.0	455.0	426.0	421.2	451.1	448	446	444	443	442	443	444	446	449	452	Yes	
385	South County West	WESTERLY 16	2TR	12.47	16F1	515	2077	241	1836	410.7	428.7	413.7	407.1	436.1	433	431	429	428	427	428	429	431	434	437		
386	South County West	WESTERLY 16	4TR	12.47	16F2	515	1859	91	1768	205.3	201.3	191.3	189.7	203.1	202	201	200	199	199	199	200	201	202	203		
387	South County West	WESTERLY 16	2TR	12.47	16F3	515	2120	329	1791	339.7	351.3	309.3	336.3	360.2	358	356	354	353	353	353	355	356	358	361		
388	South County West	WESTERLY 16	4TR	12.47	16F4	645	1692	400	1292	358.0	361.3	314.3	314.6	337.0	335	333	331	331	330	331	332	333	335	337		
389	South County West	CHASE HILL	1TR	12.47	155F2	530	2123	104	2019	276.7	286.0	261.3	251.7	269.6	268	266	265	265	264	265	265	267	268	270		
390	South County West	CHASE HILL	1TR	12.47	155F4	530	1825	184	1641	222.7	241.0	190.7	193.6	207.4	206	205	204	203	203	203	204	205	206	208		
391	South County West	CHASE HILL	1TR	12.47	155F6	530	1778	147	1631	349.3	408.7	411.3	408.2	270.0	268	267	266	265	265	265	266	267	269	270		
392	South County West	CHASE HILL	1TR	12.47	155F8	530	1491	126	1365	267.3	269.3	245.7	243.8	216.2	215	214	213	212	212	212	213	214	215	216		
393	South County West	WOOD RIVER 85	10TR	34.5	85T1	35.79	2792	254	2538	276.1	269.4	294.5	319.6	281.1	280	278	276	276	276	276	276	278	280	281		
394	South County West	WOOD RIVER 85	20TR	34.5	85T2	35.79	3	1	2	274.1	281.1	261.1	284.5	267.8	264	264	263	263	261	263	263	264	266	268		
395	South County West	WOOD RIVER 85	10TR	34.5	85T3	53.9	6	1	5	204.2	204.2	182.4	199.1	182.4	181	181	179	179	179	179	181	181	182	182		
396	TIVERTON	TIVERTON	1TR	12.47	33F1	478	1972	209	1763	412.7	434.0	382.0	352.0	309.0	306	305	304	303	302	303	304	305	307	309		
397	TIVERTON	TIVERTON	2TR	12.47	33F2	456	2518	193	2325	385.7	388.0	361.0	369.0	350.0	347	346	344	343	343	343	344	346	348	350		
398	TIVERTON	TIVERTON	1TR	12.47	33F3	478	2440	207	2233	425.7	393.3	400.3	389.0	371.0	368	366	365	364	363	364	365	366	369	371		
399	TIVERTON	TIVERTON	2TR	12.47	33F4	456	1851	131	1720	402.0	395.0	373.3	391.0	296.0	294	293	291	290	290	290	291	293	295	297		
400	TIVERTON	TIVERTON	2TR	12.47	33F6	530	2193	0	2193	0.0	0.0	0.0	0.0	282.0	280	279	278	277	276	277	278	279	281	283		

Line No.	Study Area (a)	Substation (b)	Tranf. ID. (c)	Concatenate (d)	SN Rating MVA (e)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2026 Contingency Load-at-Risk (u)	2035 Contingency Load-at-Risk (v)
						MVA (f)	MVA (g)	MVA (h)	MVA (i)	MVA (j)	MVA (k)	MVA (l)	MVA (m)	MVA (n)	MVA (o)	MVA (p)	MVA (q)	MVA (r)	MVA (s)	MVA (t)		
1	Blackstone Valley North	Nasonville #127	T271	Nasonville #127 T271	47.8	30.5	32.0	31.3	32.4	34.8	34.5	16.0	16.0	16.0	16.0	16.0	16.0	16.1	16.2	16.3	Yes	
2	Blackstone Valley North	Staples #112	T124	Staples #112 T124	47.8	27.5	25.9	24.3	26.1	26.1	25.9	25.7	25.4	25.4	25.4	25.4	25.3	25.3	25.5	25.7	Borderline	Borderline
3	East Bay	BARRINGTON 4	1	BARRINGTON 4 1	35.19	18.5	17.6	15.8	17.4	17.4	17.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Yes	
4	Providence	Elmwood #7 (12.47 kV)	T2	Elmwood #7 (12.47 kV) T2	40.58	24.2	24.1	21.8	23.3	26.0	25.8	25.8	25.8	25.9	26.0	26.1	26.2	26.3	26.5	26.8	Yes	
5	South County East	TOWER HILL 88	1	TOWER HILL 88 1	51	32.6	32.8	29.2	29.9	32.3	32.3	32.3	32.3	32.4	32.6	32.7	32.8	33.0	33.4	33.8	Yes	
6	South County West	CHASE HILL	2	CHASE HILL 2	54.3	23.8	24.1	19.1	26.0	26.6	26.6	26.6	26.6	26.7	26.8	26.9	27.0	27.1	27.4	27.8	Yes	

RHODE ISLAND ENERGY
2024 Electric Peak (MW) Forecast
15-Year Long-Term
2025 to 2039

December 2024

Energy Planning, Analysis, & Forecasting



Rhode Island Energy™
a PPL company

GENERAL NOTES

General Notes:

- Hourly load data through August 2024; projections from 2024 winter forward.
- Economic data is from Moody's vintage Summer 2024.
- Energy Efficiency, electric heating, solar, energy storage, and demand response is internal data vintage Summer 2024.
- Electric Vehicle, for medium- and heavy- duty electric vehicles and E-buses, data is S&P Global (formerly POLK) data vintage Summer 2024.
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (Jan. 2003 to Jun. 2024), internal unreconciled **preliminary** data (Jul. 2024 to Sep. 2024).
- Peak load data is metered zonal load, but without ISO bulk system losses.

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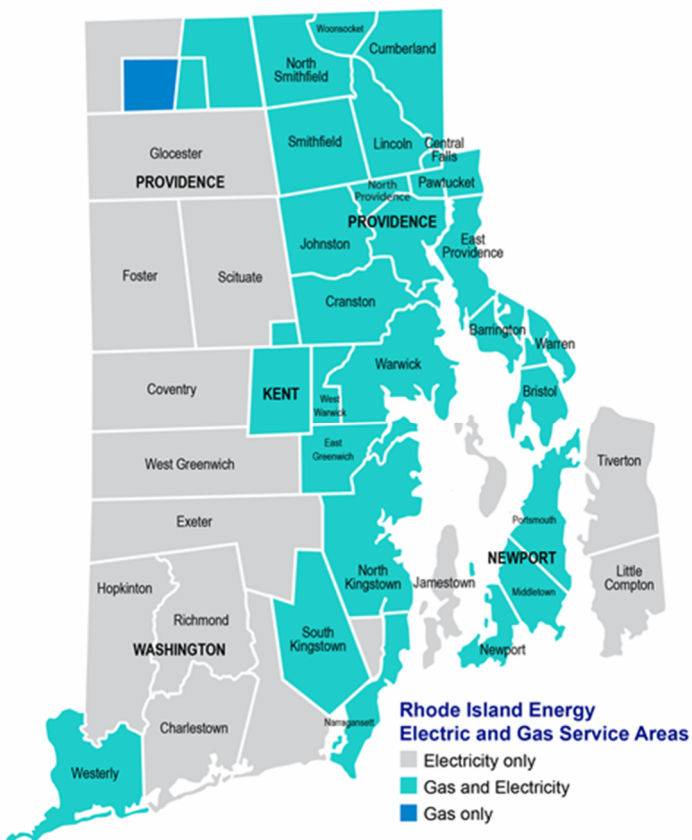
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Summary

Rhode Island Energy

Rhode Island Energy (“RIE” or the “Company”), formerly known as Narragansett Electric Company, serves approximately 486,000 electricity customers in Rhode Island. Figure 1 shows the Company’s service territory.

Figure 1: Rhode Island Energy Service Territory



The goal of the Company’s planning process is to provide safe, reliable service at the lowest reasonable cost to customers while complying with all laws and regulations. Electricity is vital to Rhode Island’s economy and public safety, and customers expect electricity to be available at all times and in all weather conditions. An understanding of the way customers use electricity is critical for planning a distribution system that can reliably serve customers in every moment. Forecasting peak electric load is necessary for the Company’s planning processes so the Company can assess the reliability of its electrical infrastructure, procure and build required facilities in a timely manner, and provide system planning with information to prioritize and focus their efforts.

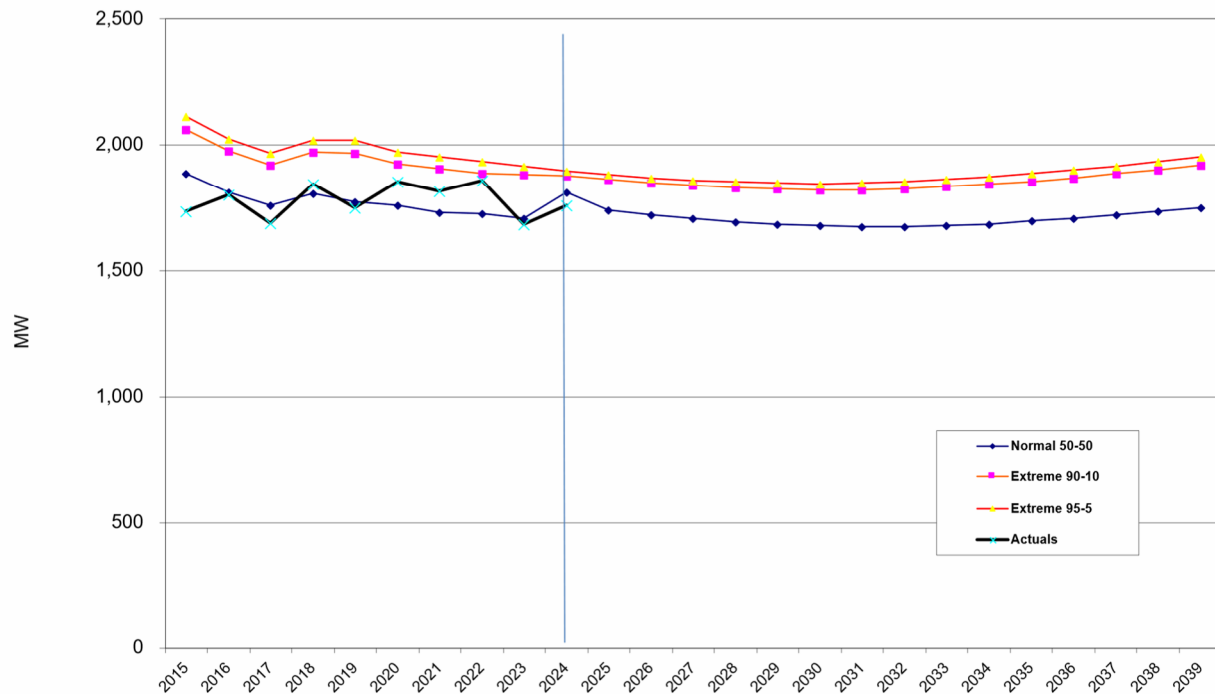
The Company’s peak demand in 2024 was 1,759 MW on Friday, August 2 at hour-ending 16. This 2024 peak was 11% below the company’s all-time peak of 1,985 MW reached on Wednesday, August 2, 2006.

This summer’s temperature for the Company peak was below average. The temperature at peak fell in the 5th percentile of peak weather over the last 20 years and was the lowest in the last 20 years. This means that 95% of summer peaks are expected to be warmer. As a result, this year’s peak is approximately 54 MW below the peak that would have experienced under normal peak weather conditions. Thus, on an adjusted “normal” basis this year’s peak was estimated to be 1,813 MW, an increase of 6.2% compared to last year’s adjusted peak.

Compared to 2024 actuals, RIE expects relatively flat peak load in the 15-year forecast period characterized by slightly decreasing peak load in the next seven years followed by slight growth in the late years of the forecast horizon when slowing energy efficiency improvements are outpaced by additional load from increasing penetration of transportation electrification. Summer peak remains to be the annual peak for the Company throughout the forecast horizon. Figure 2 shows this forecast graphically.

Figure 2: Historical (Actual & Weather-Adjusted) and Projected Summer Peaks

Net SUMMER Peaks (Actuals, 50/50, 90/10 & 95/5)



Due to increasing distributed solar photovoltaics (“PV”) and electric vehicles (“EV”), the hour of the peak slightly moves over the forecast period from late afternoon/early evening to later in the evening. As this occurs, the impact of distributed PV on peak demand is less pronounced.

Forecast Methodology

To develop a peak demand forecast, the Company first forecasts reconstituted, or “gross,” peak demands, which exclude the estimated impacts of energy efficiency, distributed PV, distributed energy storage, demand response, electric vehicles, and electric heat pumps. The impacts of these “key forecast uncertainties” are then forecasted individually and added back to the gross peak demand forecast to arrive at the final, or “net,” forecast.¹

Energy efficiency, distributed PV, distributed energy storage, and demand response reduce peak demands, while electric vehicle charging can increase peak demands. Electric heat pumps (“EH”) could increase or decrease peak demands depending on the season and technology being replaced. For purposes of reconstituting history to account for electric heat pumps, the Company assumes that electric heat pumps increase winter peaks and decrease summer peaks, albeit marginally in both seasons.

The results of this forecast are used as inputs into various system planning studies. The forecast is presented for three peak weather scenarios.² The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes while distribution planning uses the 95/5. The 50/50, or normal weather scenario, is used for capacity market, strategic scenarios, incentive mechanisms, and other relevant work.

¹ These key forecast uncertainties have historically been referred to in this report as distributed energy resources or “DER.” For purposes of this year’s report, they will be referred to as “key uncertainties.”

² For purposes of this report, the term “weather” refers to temperature-driven metrics such as the daily high temperature or heat index. The term weather is not referring to storms, wind, rain, flooding, etc. which can also impact the distribution system.

Weather Assumptions

Weather data for this analysis is collected from the Providence (or T.F. Green) weather station and used to weather-normalize peak demands.

The weather variables used in modeling include daily maximum temperature, a temperature-humidity index (THI)³, and cooling degree days for the summer peak days, and daily minimum temperature, the THI, and heating degree days for the winter peak days. THI uses a weighted three-day index (WTHI)⁴ 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)⁵.

- Normal 50/50 weather is the average weather on the past 20 annual peak days.
- Extreme 90/10 weather is the level that 90% of peak weather falls below.
- Extreme 95/5 weather is the level that 95% of peak weather falls below.

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

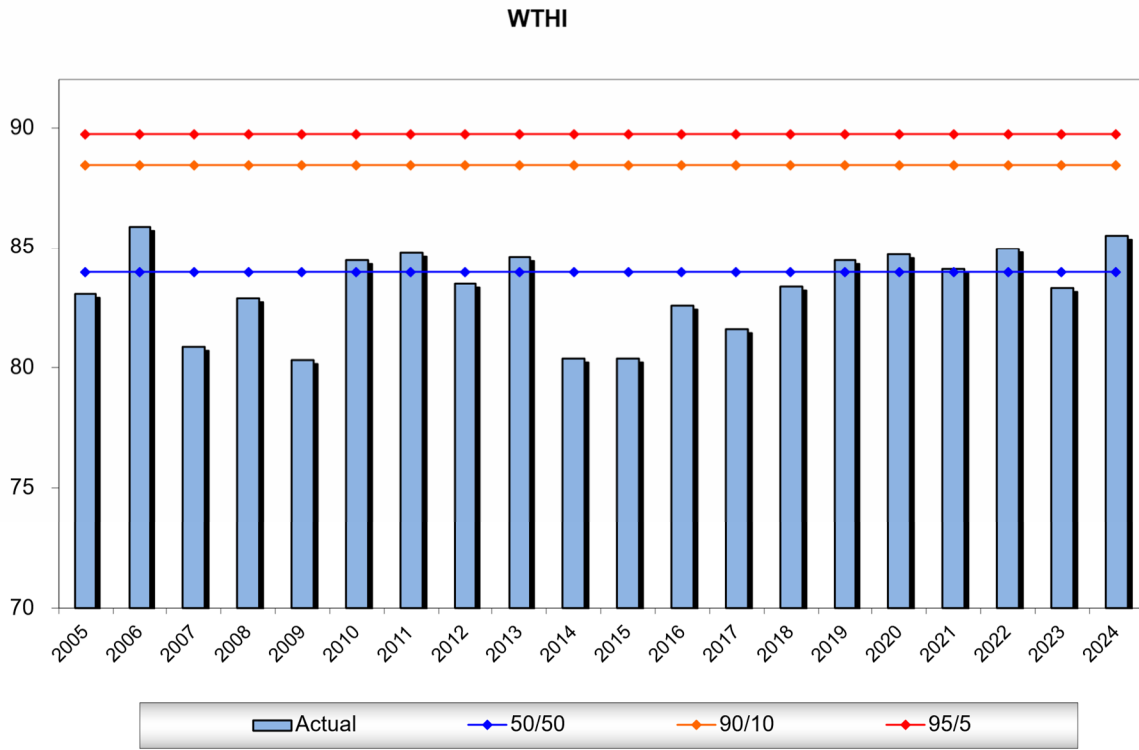
Figure 3 shows the historical, normal, and extreme weather values for WTHI for the Company.

³ THI is a calculated value also referred to as “Heat Index” provided by Accuweather. The maximum value for each day was used in the WTHI formula prior to 2023; the average of the day was used in 2023 and 2024.

⁴ WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.

⁵ Normal distribution is assumed to derive the extreme weather scenarios. This probabilistic approach employs Z-scores and standard deviations to calculate the extreme weather scenarios.

Figure 3: Actual, Normal, and Extreme WTHI



Key Forecast Uncertainties

In Rhode Island, there are a number of policies, programs, and technologies that could impact customer loads. These include, but are not limited to, energy efficiency (“EE”), distributed PV, EV, demand response (“DR”), distributed energy storage (“ES”), and EH. These collectively are termed “key uncertainties” because their impact on future peak demands is uncertain.

The Company developed base, low, and high case forecasts for each of the key uncertainties except ES and DR; only a base case forecast was developed for these items. The highest and lowest case load forecasts were developed using the most extreme cases of each uncertainty that would produce the highest and lowest load. The discussion below assumes the base case for each uncertainty.

Figure 4 shows expected net and gross load, and Figure 5 shows the impacts for the uncertainties each year. On average, gross load is projected to grow by 0.02% per year over the next five years. Net load is projected to decrease by 1.5% per year over the next five years. Over the fifteen-year forecast period, the net peak is expected to decrease by 0.6% per year due primarily to EE and the increasing penetration of distributed PV more than offsetting growth in EV.

Figure 4: Annual Gross and Net Peaks

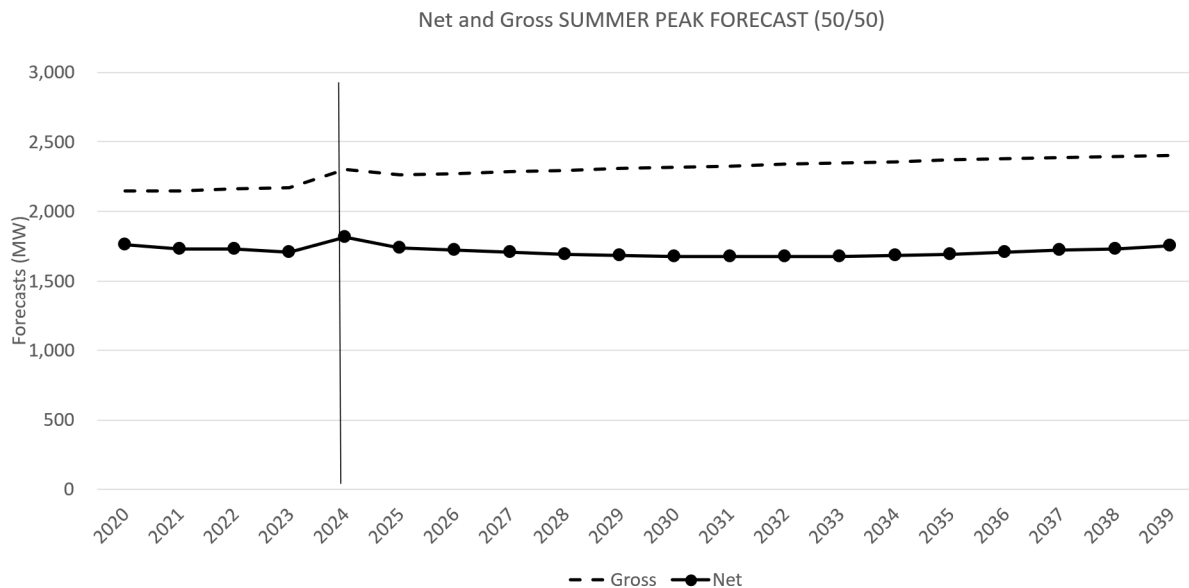
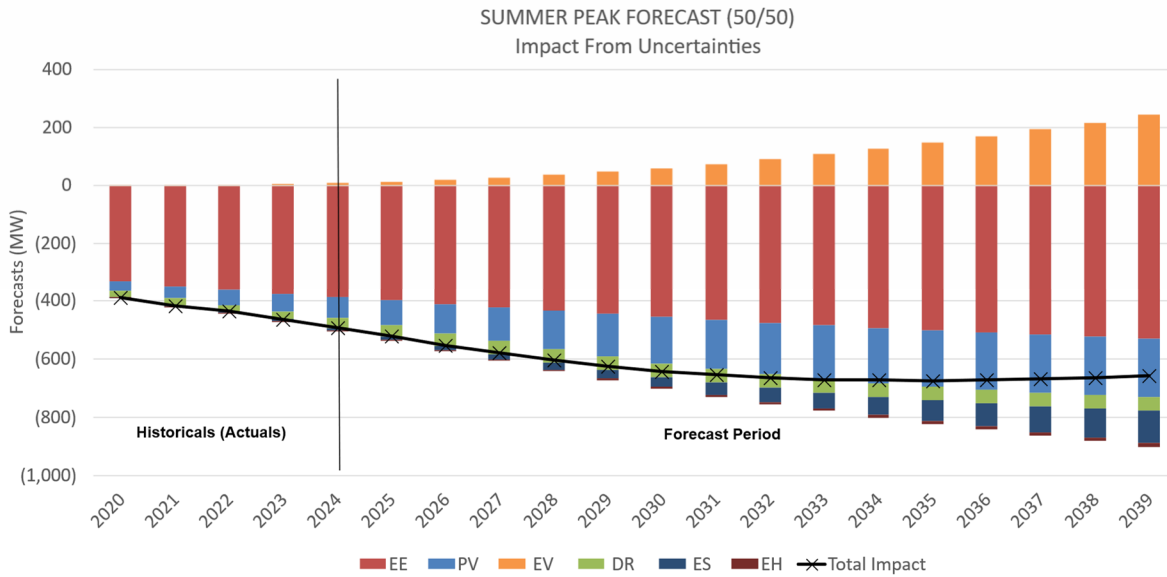


Figure 5: Impact of Key Uncertainties on Peak



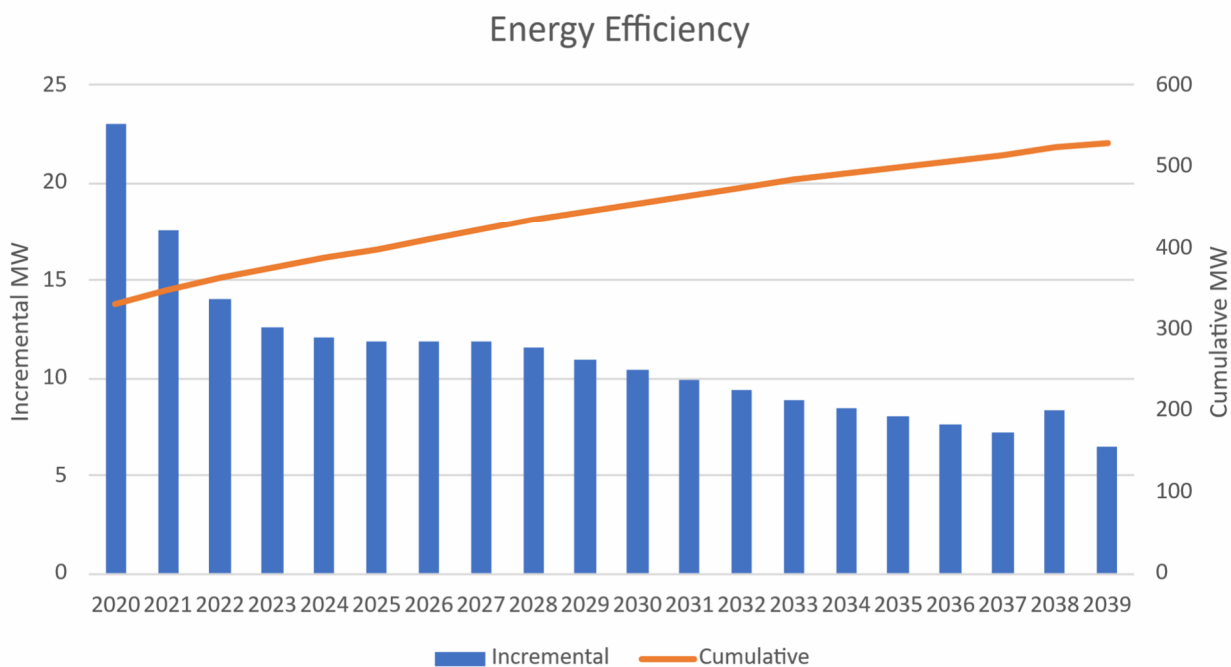
Each of the key uncertainties is discussed in the sections below.

Company-Sponsored Energy Efficiency Programs

Rhode Island Energy has sponsored EE programs for many years and will continue to do so for the foreseeable future. Estimated EE impacts for the historical period and the initial 3 years of the forecast period are based on the Company’s three-year EE plan. According to the Energy Information Administration, incremental improvements in end-use efficiencies will diminish over time as end-use efficiencies approach their technical potential, and the Company’s EE forecast is consistent with these projections.

Figure 6 below shows the base case energy efficiency program impacts to peak demands. As of 2024, these EE programs have reduced load by an estimated 387 MW, or 16.8% compared to the 2024 gross weather-normalized peak. By 2039, this reduction grows to 529 MW or 22% of what load would have been had these programs not been implemented. Over the fifteen-year planning horizon, the impact of EE reductions lower annual peak growth from 0.3% to -0.1% per year. Figure 6 presents the annual incremental (left) and cumulative (right) estimated EE summer peak MW reductions.

Figure 6: Energy Efficiency Summer MWs by Year



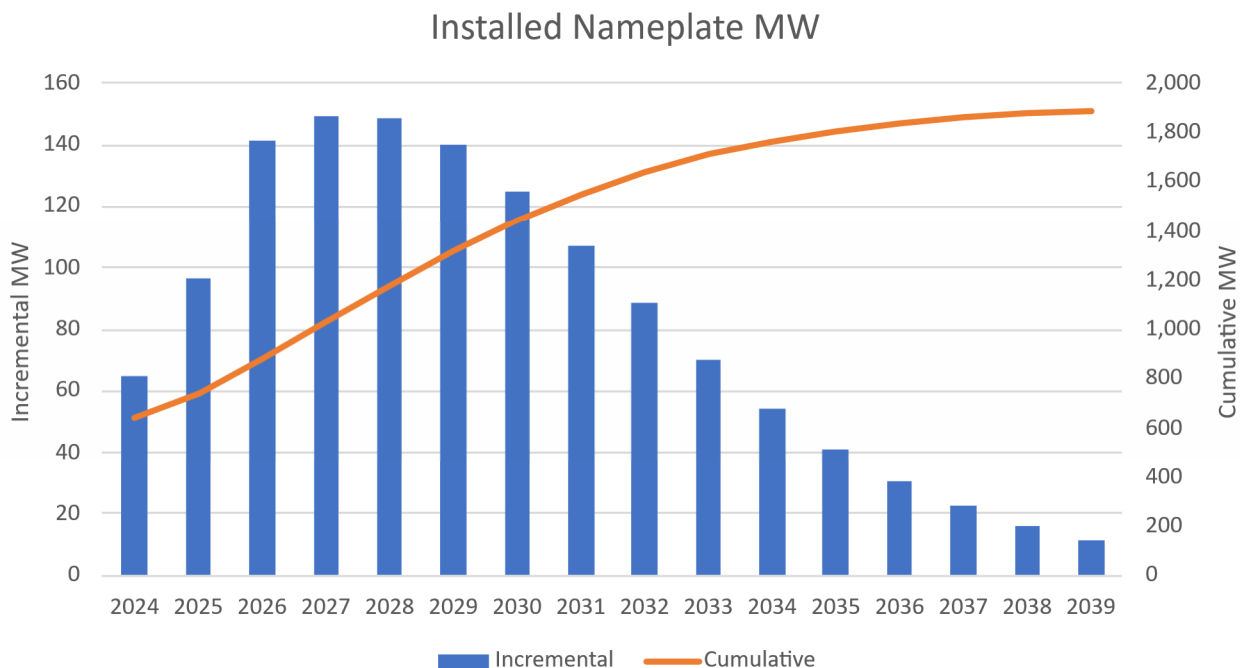
Distributed Solar Photovoltaic⁶

Actual distributed solar installations and capacity are tracked by the Company and used to estimate the historical contributions of distributed PV to peak demand. The projection for the future is based on an estimate of installations for units already in the application queue for the current year, then a continuation of those levels until year 2027, and then a slowly declining number of new annual installations to account for saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Figure 7 shows the projected connected PV installations. As of 2024, it is estimated about 645 MW will have been connected, growing to 1,888 MW by the end of the planning period.

⁶ This discussion is limited to PV which is expected to reduce loads and would not include those PV installations considered to be supply by the ISO. This can include both “behind-the-meter” and in “front-of-the-meter” (e.g. community solar which is allocated back to customers).

Figure 7: Distributed Solar-PV Connected Nameplate (AC) MW by Year



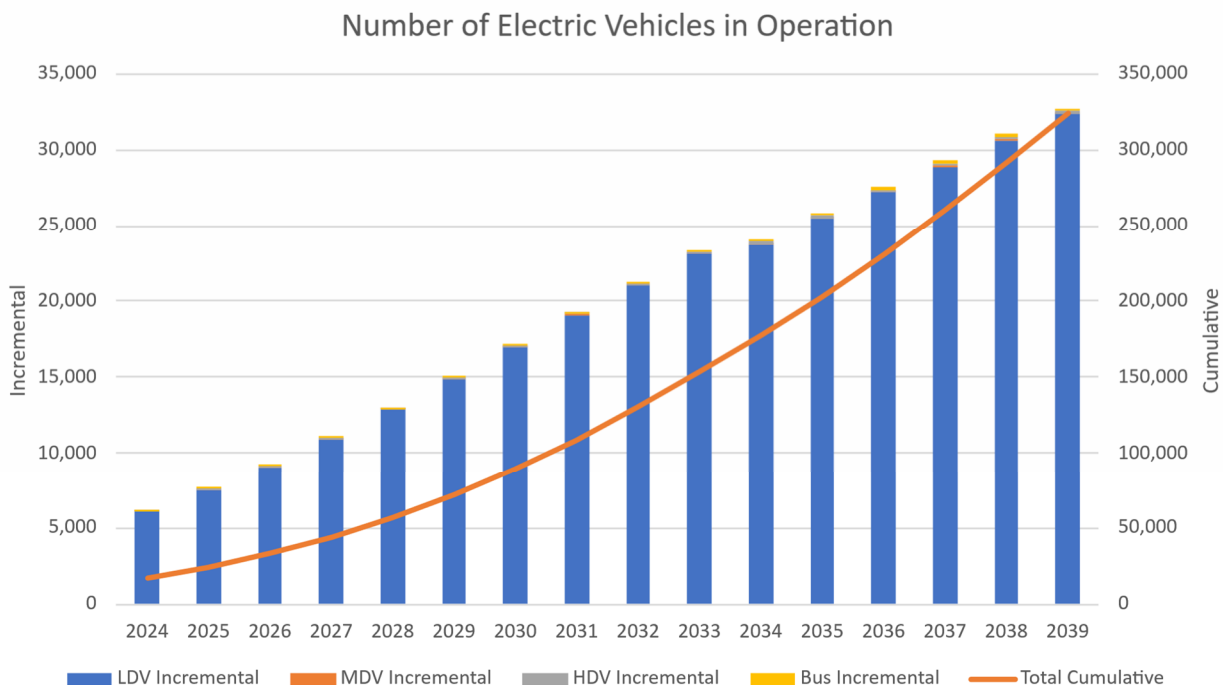
While installed distributed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less solar irradiance.

Electric Vehicles

EVs will increase peak load over time barring the introduction of rates or programs to reduce the impact. Forecasted EVs include “plug-in hybrid electric vehicles” (PHEVs) and “plug-in battery-only electric vehicles” (BEVs). While light-duty EVs (“LDV”) are assumed to by far be the most widely adopted and thus the most impactful on electric load, the Company also includes medium-duty EVs (“MDV”), heavy-duty EVs (“HDV”), and electric buses in the electric load forecast.

Figure 8 shows the future estimated number of EVs in the Company’s Rhode Island service territory. As of the end of 2024, it is estimated that about 16,772 EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in the service territory, growing to almost 325,000 by the end of the fifteen-year planning horizon.

Figure 8: Number of Incremental and Cumulative EVs



It is estimated that these vehicles may have increased cumulative summer peak loads by about 9.4MW as of 2024. This grows to 244 MW of cumulative peak load increase by 2039.

Demand Response

DR programs actively target reductions to peak demand during hours of high expected demand or hours having 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 the Independent System Operator (“ISO”) to act in response to a system reliability concern or pricing signals. During these events, a customer 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 – 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. The Company’s policy has been to add-back reductions from these dispatches to its reported system peak numbers. Because the Company cannot dispatch the ISO resources, 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.

The Company recently began to run its own DR program, referred here as “retail DR,” over the last few years. In contrast to the wholesale level DR programs implemented by the ISO, the retail programs are activated by the Company.

In 2024, estimated impact of the retail DR program was about 35 MW and is expected to grow to about 46 MW by year 2029. No additional incremental DR MW is expected beyond that point because it is assumed that the program's market potential is at its maximum by then, but the cumulated MW is expected to be carried through the rest of the forecast horizon.

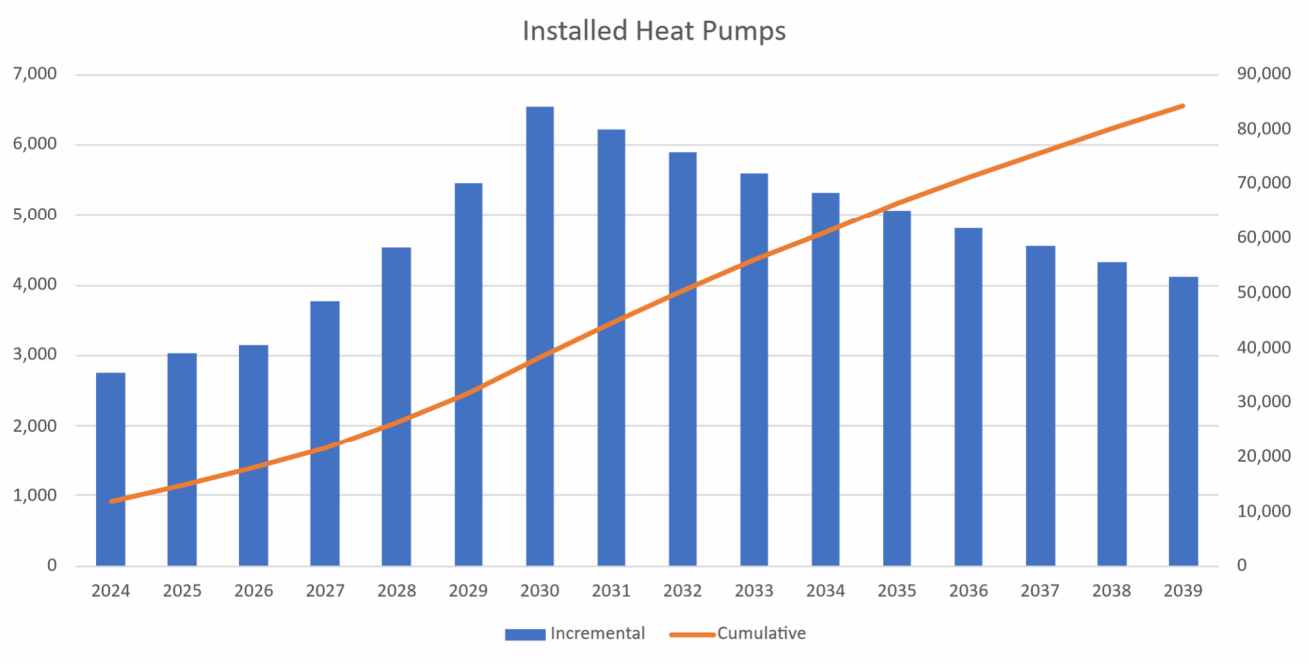
Distributed Energy Storage

Rhode Island Senate Bill 2499, known as the "Energy Storage Systems Act," recently established targets for energy storage capacity of 90 MW by December 31, 2026, 195 MW by December 31, 2028, and 600 MW by December 31, 2033. These targets were not directly incorporated into the forecast as the mechanisms by which these targets will be achieved have not yet been defined. While the act does not include provisions for specific funding, some financial incentives are currently available. CommerceRI's Renewable Energy Fund (REF), the federal Inflation Reduction Act, and the Company's ConnectedSolutions Battery Program all include provisions for battery storage. With these provisions, about 2.32 MW of storage was installed through 2023. By 2038, it is estimated that storage may help shave the summer peak load by about 72 MW. It is also noted that there is a small amount of storage being captured in the Company's Demand Response program in Rhode Island through the ConnectedSolutions program. By May 1, 2025, the Public Utilities Commission will adopt a framework for an energy storage system interconnection tariff that will more clearly outline the monetary incentive to adopt these systems.

Electric Heat Pumps

The base case for electric heat pump adoptions is based on the Company's pro rata share of the ISO-NE heat electrification forecast, which is a projection for residential heat pumps installations in the state. Commercial heat pumps are not currently incentivized. Incremental adoption continues to grow until 2030, at which point incremental growth begins slows down. Figure 9 shows the annual number of electric heat pumps assumed for the forecast.

Figure 9: Number of Electric Heat Pumps



All prior discussion on load and uncertainties above is limited to the base case. Additional high and low scenarios are provided later in this section (see “Key Forecast Uncertainties Scenarios”) and in the Appendices.

Peak Day 24 Hour Load Curves

While the single hour peak values discussed above are of major importance, the Company forecasts demand and the impact of key uncertainties for all hours of the peak day in each year. This approach is useful to show the changing hours of the peaks as the level of different uncertainties change over time. For example, as more and more PV is added to the system, the summer peak hour will shift away from afternoon hours where solar irradiance is highest to evening hours as the solar reductions taper off. As more electric vehicles are adopted, evening and nighttime loads could go up depending upon measures that could be taken to incentivize customers to charge at different hours of the day.

Figure 10 shows the hourly profile of the peak summer day for selected years over the planning horizon for the base case uncertainties.

Figure 10: Net and Gross Peak Summer Day Hourly Load

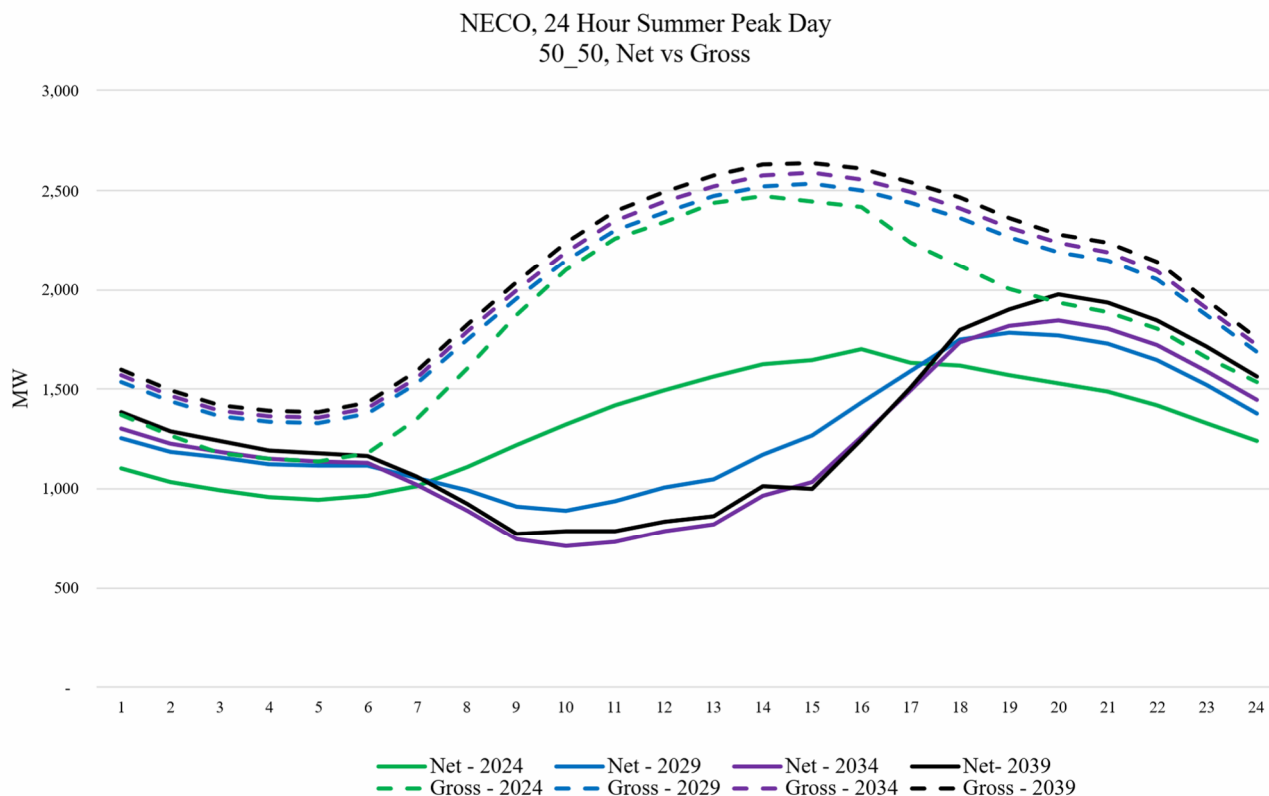


Figure 10 clearly shows how the expected uncertainties not only lower the loads, but also shift the hour of the peaks.

Figure 11 shows the hourly profile of the peak winter day for selected years over the planning horizon with the base case uncertainties.

Figure 11: Net and Gross Peak Winter Day Hourly Load

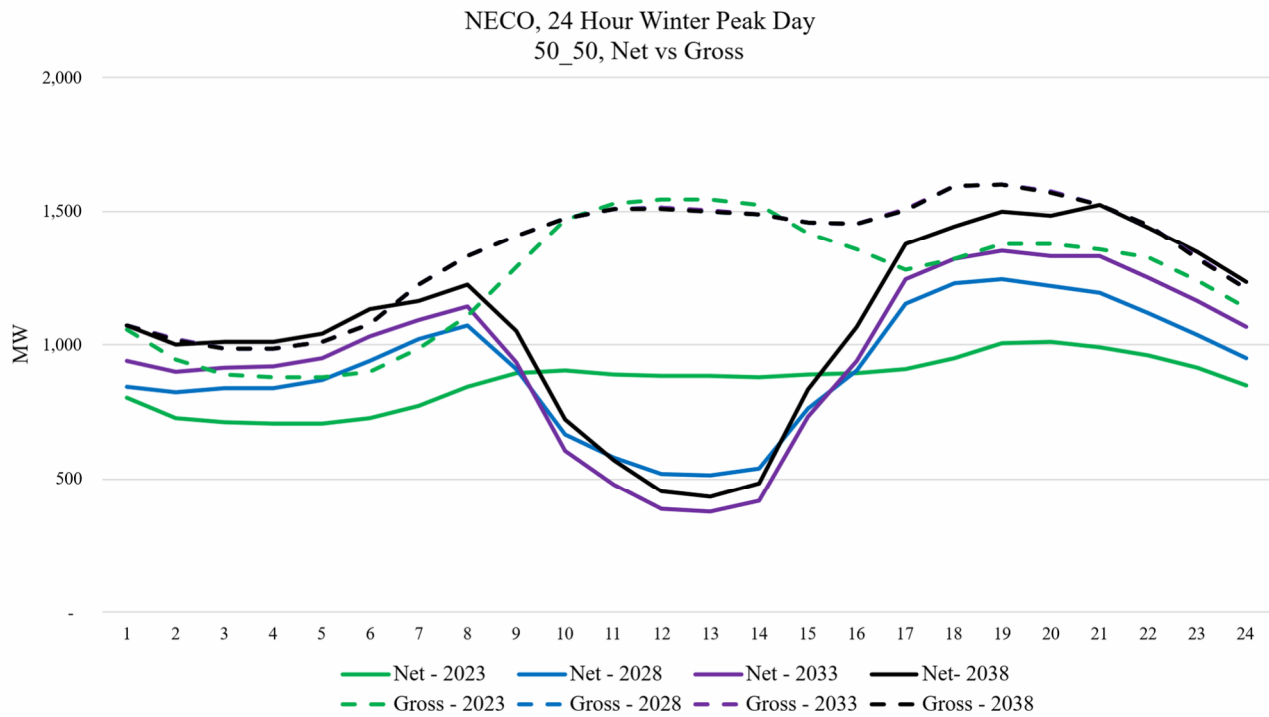


Figure 11 shows the dual peaks associated with winter days as well as the potential for very low load hours during the daytime due to solar and the rapid ramp needed as the sun sets. An increasing penetration of electric heat pumps and electric vehicles could increase morning and evening usage in later years of the forecast period. The figures above show the gross and net load profiles for the base case uncertainties.

Appendix C contains additional hourly 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 reduced commercial and industrial load.

Key Forecast Uncertainties Scenarios

Thus far, this report has shown results for the peak forecast with the base case forecasts for key uncertainties. The Company also developed high and low case scenarios for the following key uncertainties: EE, PV, EV, and EH. Looking at a range of scenarios can provide planners with additional information on what loads might be under high and low scenarios.

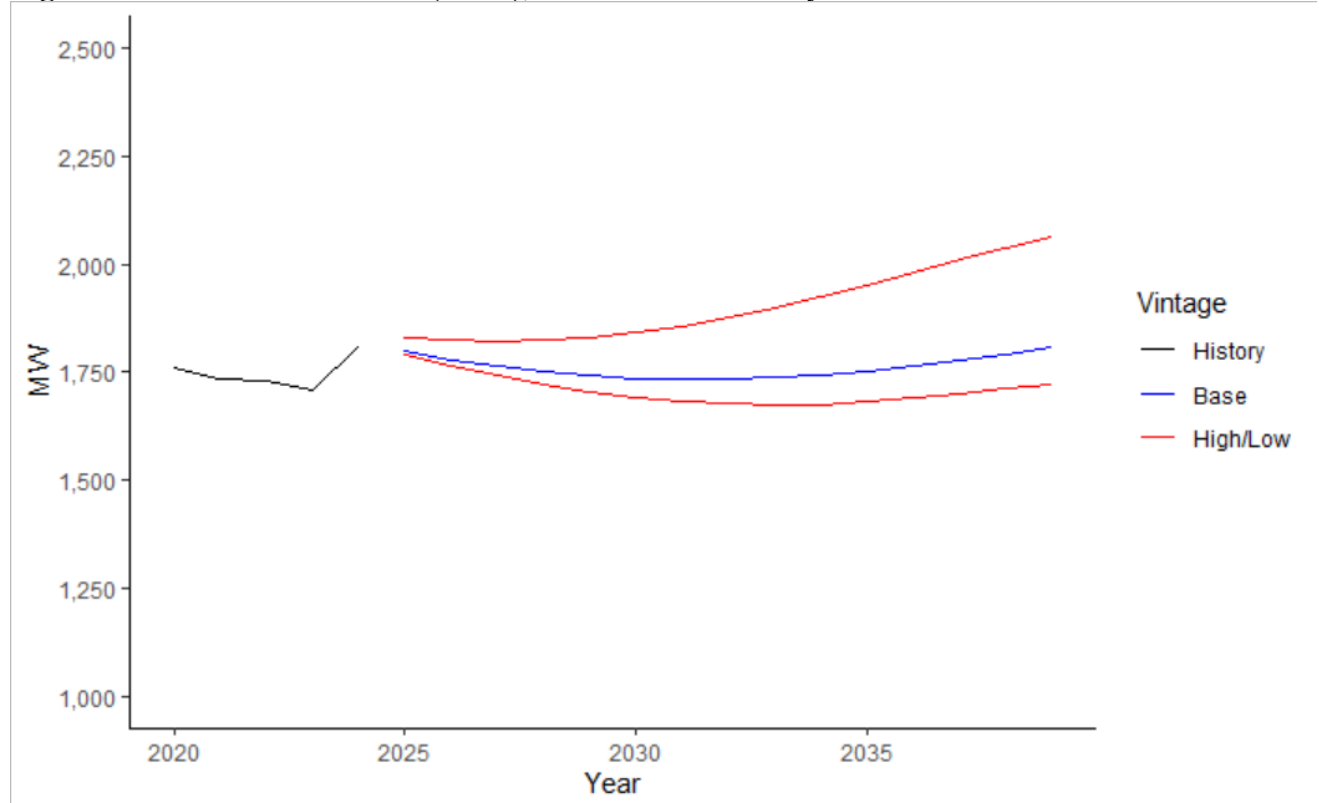
Each of the various combinations of uncertainty scenarios – base, high, and low – were modeled.⁷ While this creates many combinations, the Company chose to focus primarily on the base, high, and low load cases created by the uncertainty combinations.

Figure 12 shows the base case (which the Company deems to be the most reasonable scenario) as a continuation of the historical normalized data and the maximum and minimum cases in red lines which provide the highest and lowest load bounds for planning purposes. The base is the scenario with base cases from all uncertainties. The maximum load scenario is the scenario where load reducing key uncertainties such as energy efficiency and PV are minimized, while load increasing key uncertainties such as EVs are maximized. The minimum load scenario is the scenario where load reducing key uncertainties are maximized and load increasing key uncertainties are minimized.

The peak load five years from now in year 2029 ranges from 1,704 MW to 1,830 MW - a 126 MW spread, with the base case at 1,741 MW. The uncertainty increases over time, so that fifteen years from now in year 2039 the range expands to 1,723 MW to 2,062 MW, or a 339 MW spread, with the base case at 1,809 MW. It is noted that while the maximum and minimum cases are shown to provide bounds for the forecast, those specific scenarios are unlikely.

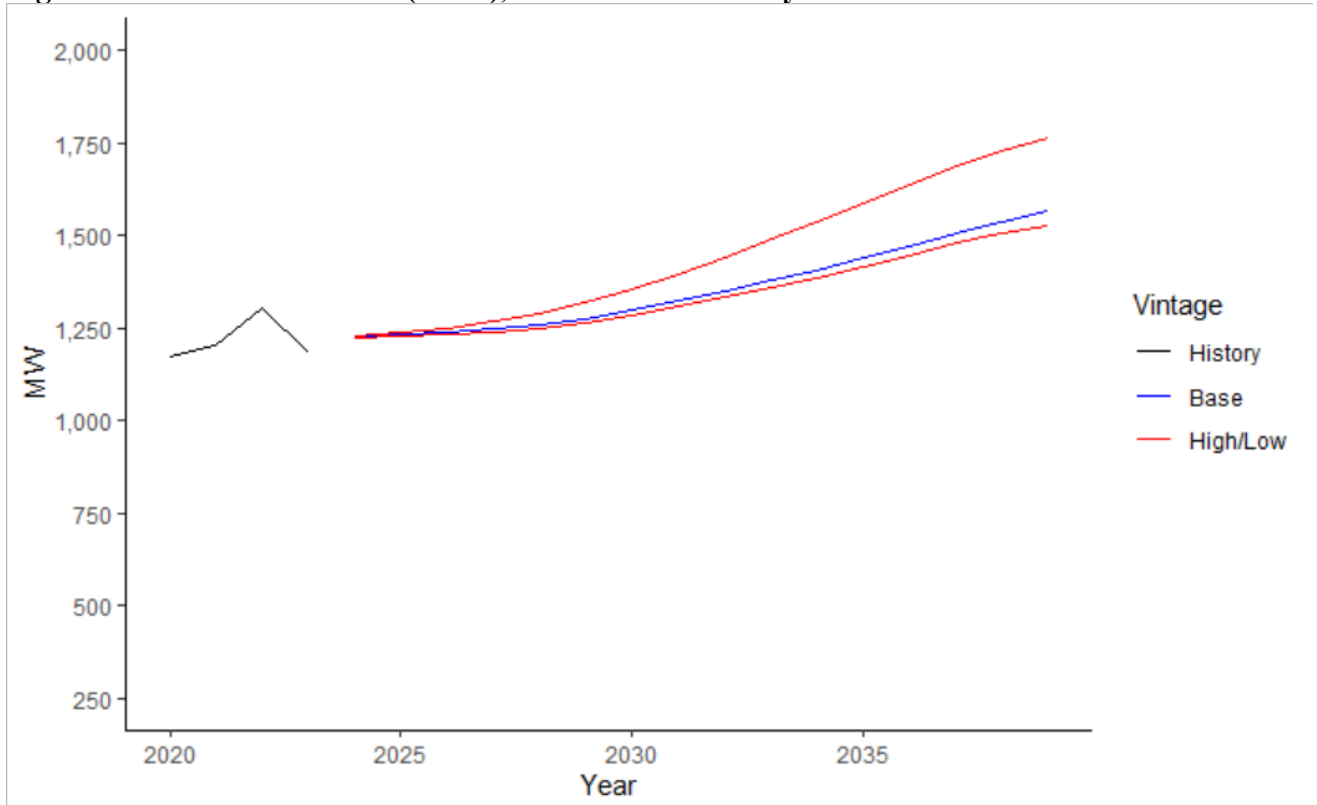
⁷ The base case uncertainty projections included in this forecast are based on current trends, approved programs, and existing state policy targets. They are considered the most probable scenario at this time. The higher and lower scenarios are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive. These can include, among other things, additional electrification of the transportation and heating sectors and managed EV charging. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

Figure 12: Net Summer Peaks (50/50), Selected Uncertainty Scenarios



Although summer peaks remain to be the annual peak throughout the forecast horizon, winter peaks attract increasing interest with the potential for electric space heating growth in the future. Figure 13 shows the winter peak load of selected uncertainty scenarios through the end of the forecast horizon in the same format as Figure 12. Please note, because the winter peak hour is expected to be hour-ending 19 or later, solar irradiance is not expected to be available for these projected peak hours and thus there is no PV saving expected for the net peak hour in winter.

Figure 13: Net Winter Peaks (50/50), Selected Uncertainty Scenarios



While Figure 12 and Figure 13 above show what the longer term annual single summer peaks and winter peaks look like, Figure 14 and Figure 15 show peak day hourly profiles for selected years.

Figure 14: 50/50 Case, Net Summer Peak with Range of Uncertainty Scenarios, 2029

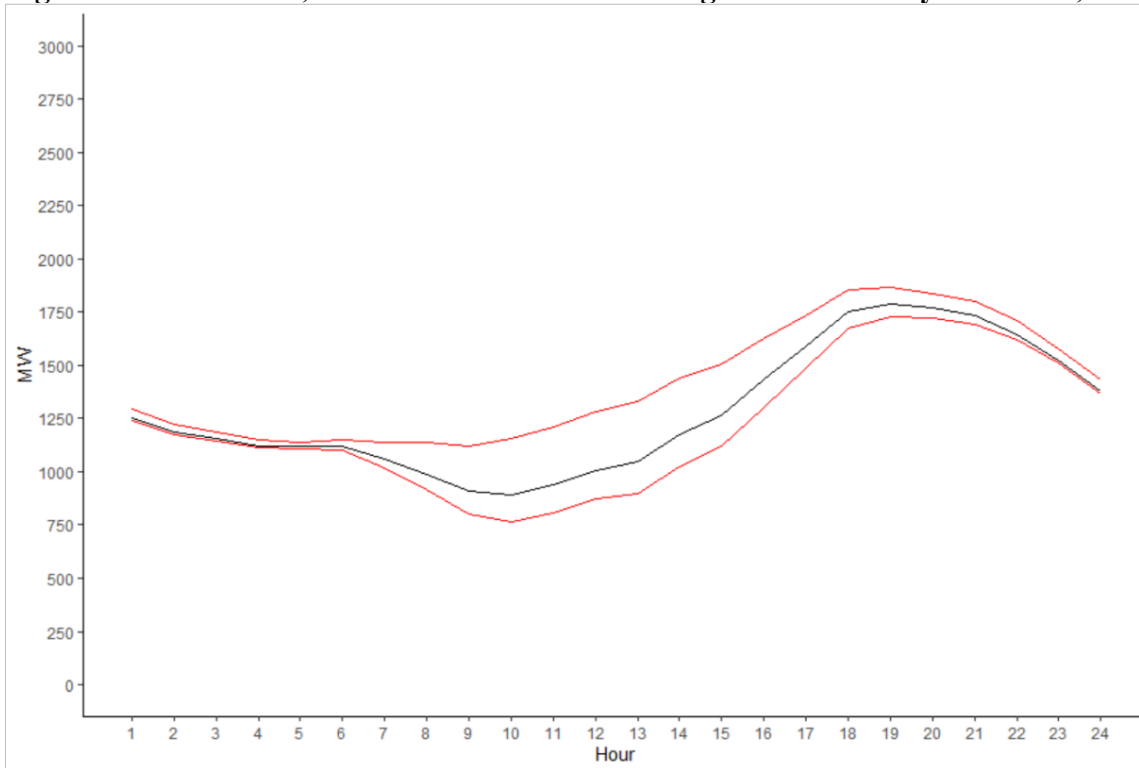


Figure 15: 50/50 Case, Net Summer Peak, with Range of Uncertainty Scenarios, 2039

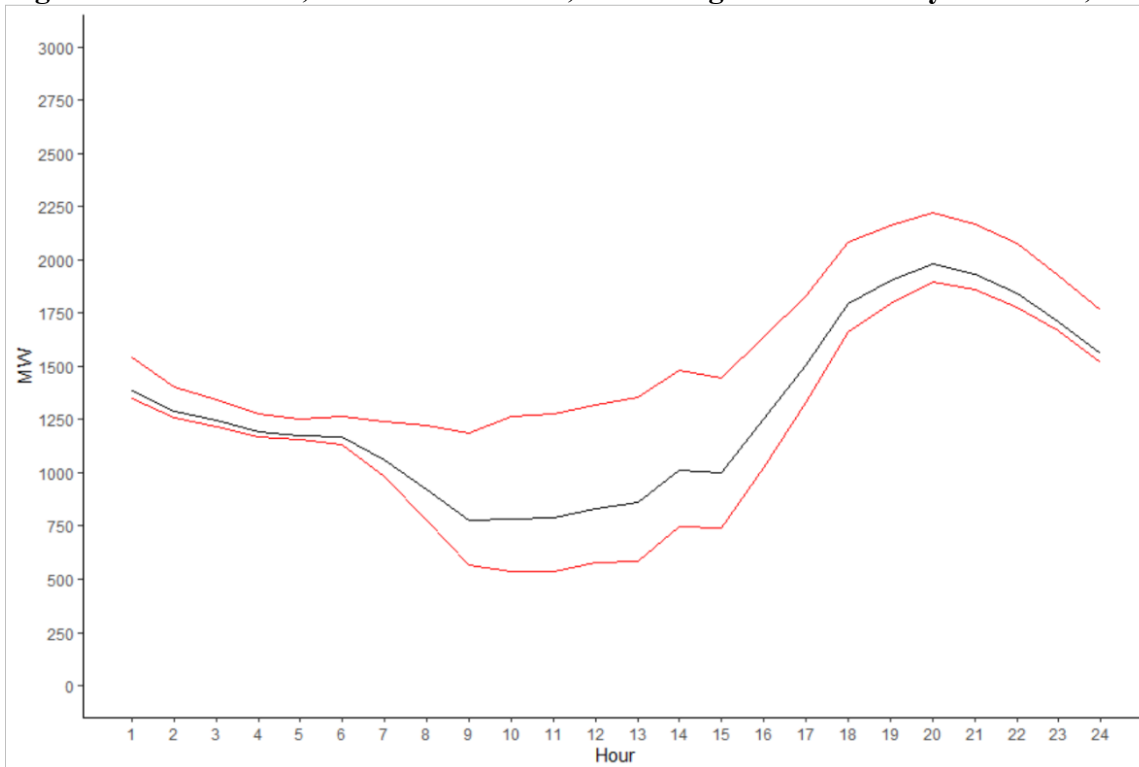


Figure 16: 50/50 Case, Net Winter Peak, with Range of Uncertainty Scenarios, 2028

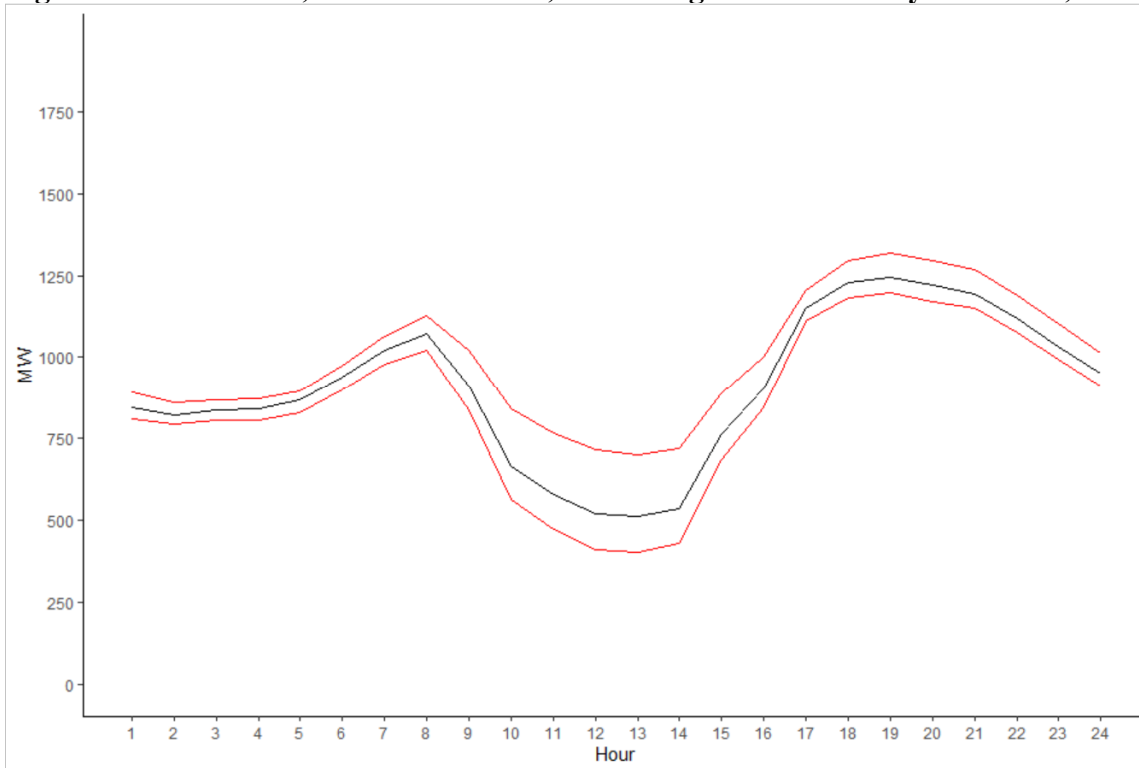
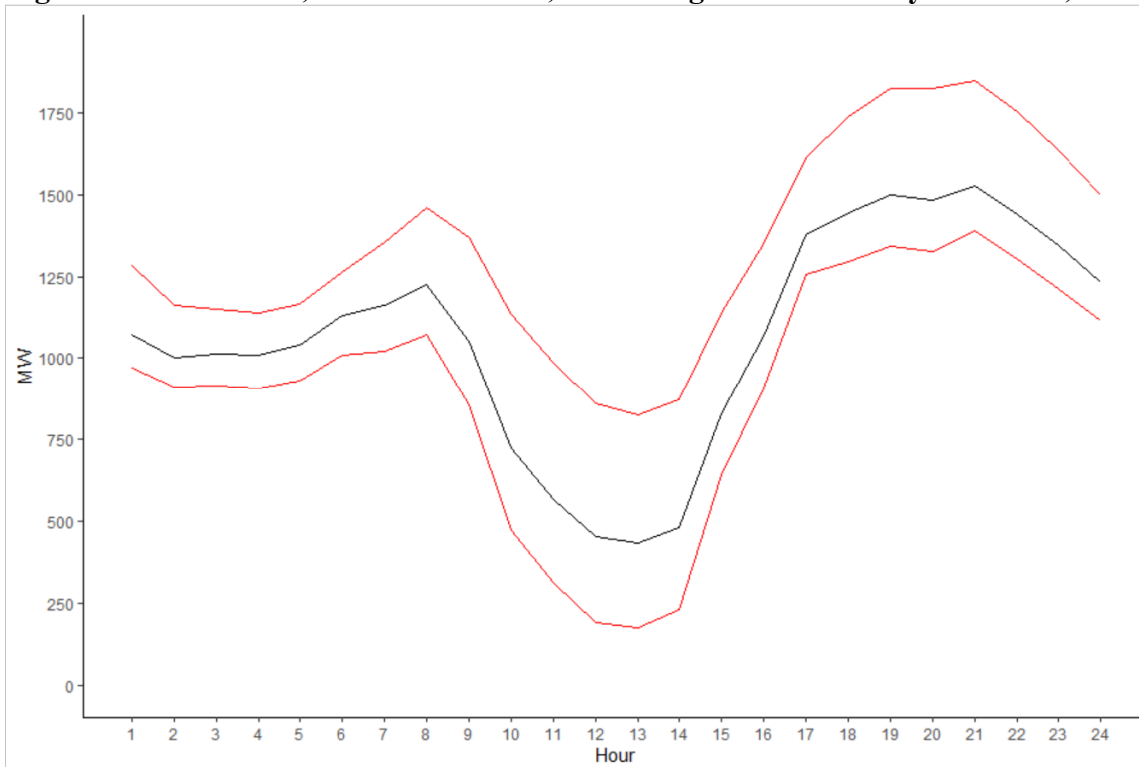


Figure 17: 50/50 Case, Net Winter Peak, with Range of Uncertainty Scenarios, 2038



What becomes apparent is that the range of possible outcomes in the early years (Figure 14 and Figure 16) is more narrow, but increases fifteen years out (Figure 15 and Figure 17). Note that the midday hours have a wider range of possible loads than other times of the day primarily because of the distributed solar resource.

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

Extreme Weather Analysis

Seasonal peaks are highly dependent upon extreme weather, and they typically occur on some of the hottest days of the summer and coldest days of the winter. While the trend in average annual temperatures has been slightly increasing in recent decades, the trend in annual high and low temperatures has been mostly flat.

Figure 18 and Figure 19 show annual high and low temperatures since the early 1970s. Based on the 10- and 20-year rolling averages, the trend in annual winter low temperatures has been flat to slightly declining (getting colder) since 2010. The figures also show the wider range of winter low temperatures relative to summer high temperatures. This means that the winter peak can deviate from the mean far more than the summer peak. The figures also show that the 20-year rolling average is more stable and less impacted by one year being added to or rolling off the rolling average than the 10-year rolling average, particularly for the more volatile low temps.

Because the weather data does not support a warming trend in seasonal extreme temperatures, the Company’s peak forecast does not contemplate warming extreme temperatures in the future.

Figure 18: Historical Annual High Temperatures (°F)

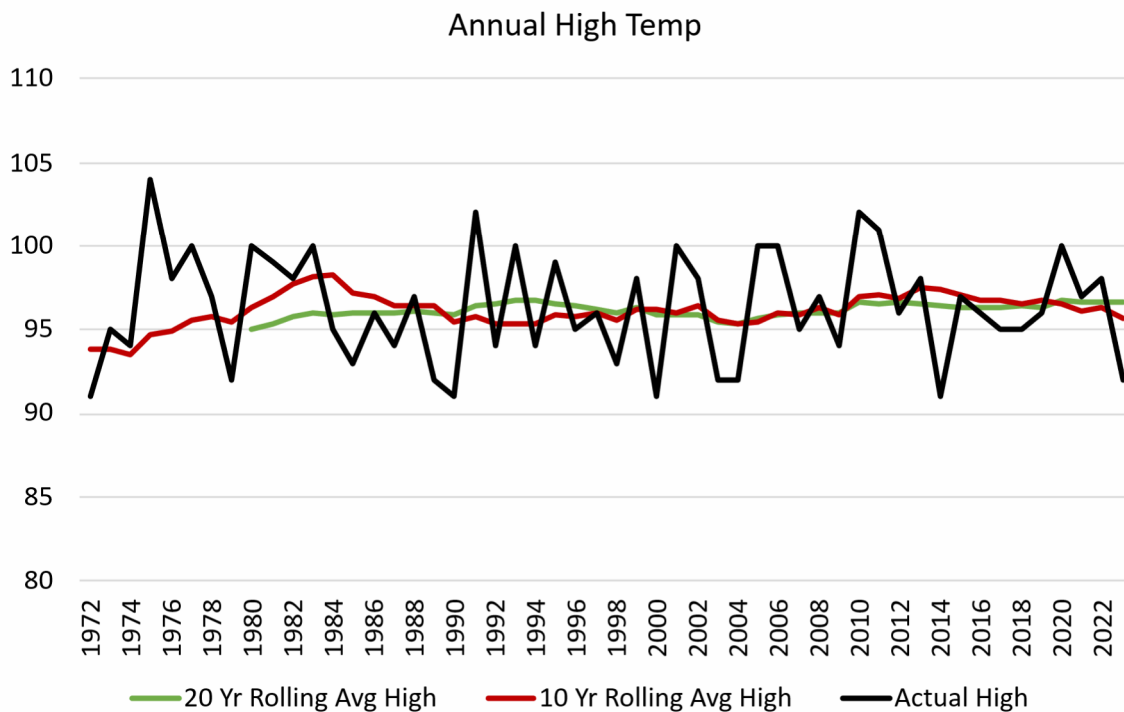
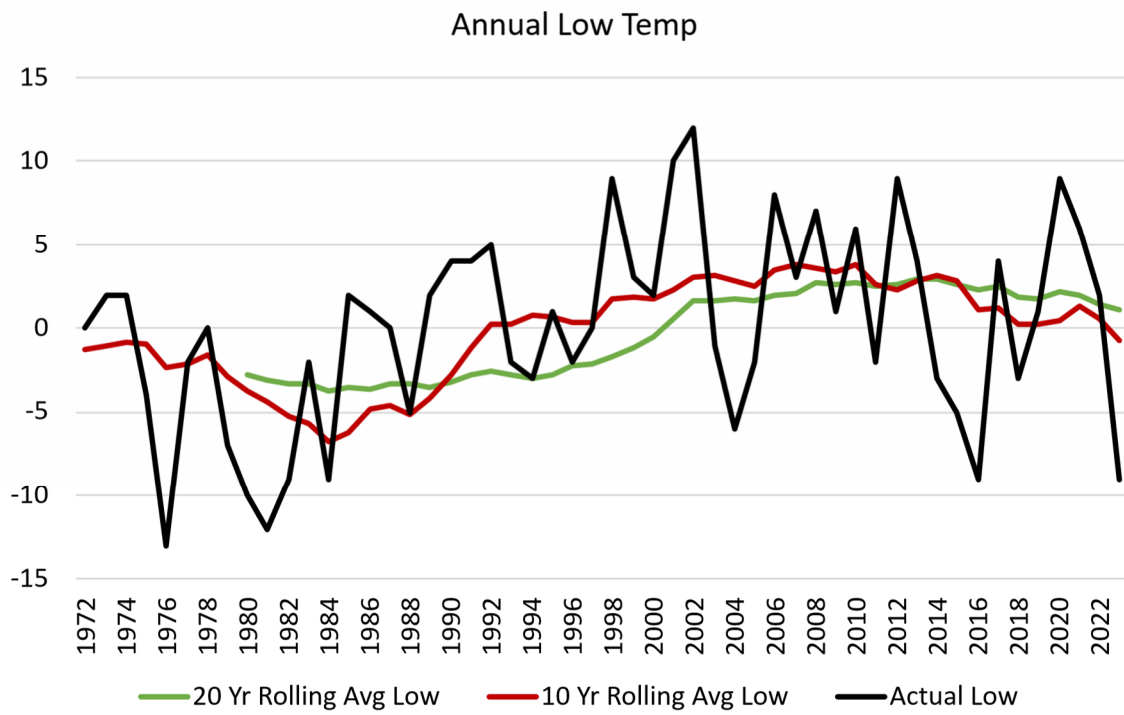


Figure 19: Historical Annual Low Temperatures (°F)



Comparison of 2024 Forecast to 2023 Forecast

Figure 20 provides a comparison of this year’s summer peak (which is also the annual peak) forecast to last year’s forecast. Generally speaking, there is very little difference between the gross forecasts, and the net forecasts are similar to the forecasts released in 2023.

Figure 20: Comparison of Current Forecast to Prior Forecast, Gross and Net, Summer 50-50

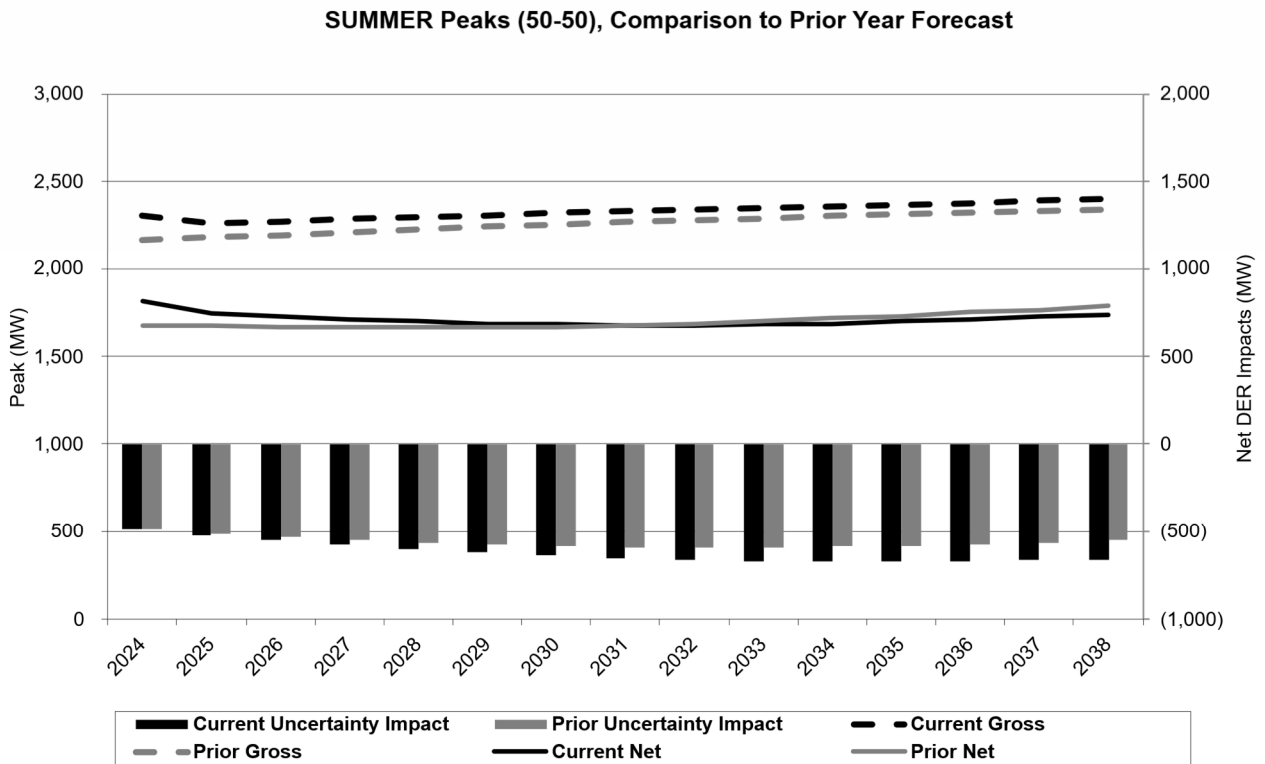
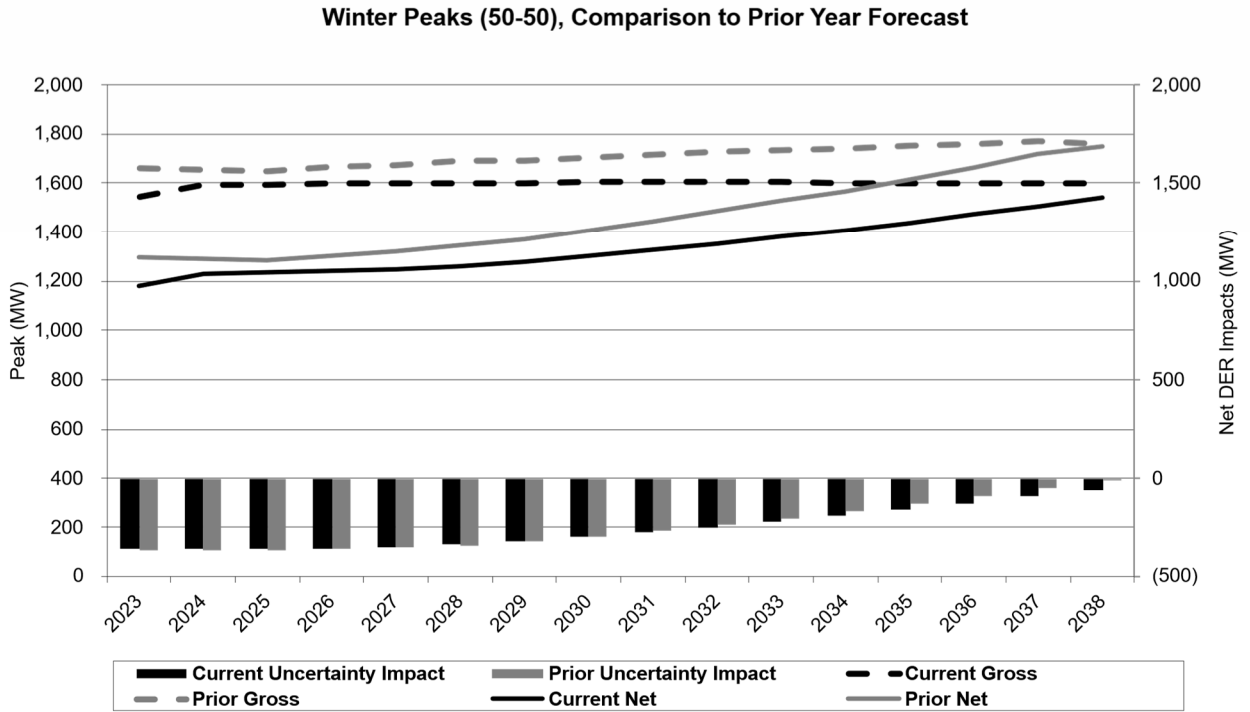


Figure 21 provides a comparison of this year’s winter peak forecast to last year’s forecast.

Figure 21: Comparison of Current Forecast to Prior Forecast, Gross and Net, Winter 50-50



Appendix A: Forecast Details

**NECO
SUMMER Peaks**

Net *

YEAR	Actuals		Normal 50-50		Extreme 90-10		Extreme 95-5		WTHI
	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	ACTUAL
2008	1,824		1,847		1,991		2,032		82.9
2009	1,713	-6.1%	1,849	0.1%	2,014	1.2%	2,061	1.4%	80.3
2010	1,872	9.3%	1,834	-0.8%	1,998	-0.8%	2,045	-0.8%	84.5
2011	1,974	5.5%	1,852	1.0%	2,015	0.9%	2,061	0.8%	84.8
2012	1,892	-4.2%	1,855	0.1%	2,005	-0.5%	2,047	-0.7%	83.5
2013	1,965	3.9%	1,852	-0.1%	2,015	0.5%	2,061	0.7%	84.7
2014	1,653	-15.9%	1,846	-0.4%	2,011	-0.2%	2,057	-0.2%	80.4
2015	1,738	5.1%	1,887	2.2%	2,065	2.7%	2,115	2.8%	80.4
2016	1,803	3.8%	1,813	-3.9%	1,977	-4.3%	2,023	-4.4%	82.6
2017	1,688	-6.4%	1,759	-3.0%	1,923	-2.7%	1,969	-2.7%	81.7
2018	1,847	9.4%	1,807	2.8%	1,973	2.6%	2,020	2.6%	83.4
2019	1,750	-5.3%	1,774	-1.8%	1,966	-0.3%	2,021	0.0%	84.5
2020	1,855	6.0%	1,762	-0.7%	1,925	-2.1%	1,972	-2.4%	84.7
2021	1,819	-2.0%	1,734	-1.6%	1,906	-1.0%	1,955	-0.8%	84.1
2022	1,859	2.2%	1,728	-0.3%	1,890	-0.9%	1,935	-1.0%	85.0
2023	1,684	-9.4%	1,707	-1.2%	1,883	-0.3%	1,915	-1.0%	83.3
2024	1,759	4.5%	1,813	6.2%	1,877	-0.3%	1,895	-1.1%	85.5
2025	-	-	1,741	-4.0%	1,865	-0.6%	1,884	-0.6%	
2026	-	-	1,723	-1.1%	1,850	-0.8%	1,870	-0.7%	
2027	-	-	1,708	-0.8%	1,840	-0.6%	1,861	-0.5%	
2028	-	-	1,695	-0.8%	1,831	-0.5%	1,853	-0.4%	
2029	-	-	1,685	-0.6%	1,824	-0.4%	1,848	-0.3%	
2030	-	-	1,678	-0.4%	1,821	-0.2%	1,846	-0.1%	
2031	-	-	1,675	-0.2%	1,822	0.1%	1,848	0.1%	
2032	-	-	1,676	0.0%	1,827	0.2%	1,854	0.3%	
2033	-	-	1,681	0.3%	1,834	0.4%	1,862	0.5%	
2034	-	-	1,686	0.3%	1,845	0.6%	1,874	0.7%	
2035	-	-	1,696	0.6%	1,856	0.6%	1,886	0.6%	
2036	-	-	1,707	0.6%	1,871	0.8%	1,901	0.8%	
2037	-	-	1,721	0.8%	1,886	0.8%	1,918	0.9%	
2038	-	-	1,735	0.8%	1,902	0.8%	1,934	0.8%	
2039	-	-	1,752	1.0%	1,921	1.0%	1,953	1.0%	

Annual Avg. 15 yr ('09 to '24)	-0.1%	-0.5%	-0.6%
Annual Avg. 10 yr ('14 to '24)	-0.2%	-0.7%	-0.8%
Annual Avg. 5 yr ('19 to '24)	0.4%	-0.9%	-1.3%
Annual Avg. 5 yr ('24 to '29)	-1.5%	-0.6%	-0.5%
Annual Avg. 10 yr ('24 to '34)	-0.7%	-0.2%	-0.1%
Annual Avg. 15 yr ('24 to '39)	-0.2%	0.2%	0.2%

WTHI	
NORMAL	84.0
EXTREME 90/10	88.5
EXTREME 95/5	89.8

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

NECO		SUMMER 50/50 Peaks (MW) (Gross and Net)																				
Calendar Year	SYSTEM PEAK							Net	UNCERTAINTY IMPACTS						Total Impact	EE % of 'Recon'd' Deliveries	PV % of 'Recon'd' Deliveries	EV % of 'Recon'd' Deliveries	DR % of 'Recon'd' Deliveries	ES % of 'Recon'd' Deliveries	EH % of 'Recon'd' Deliveries	Total % of 'Recon'd' Deliveries
	Gross	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only		EE Forecast	PV Forecast	EV Forecast	DR Forecast	ES Forecast	EH Forecast								
2008	1,904	1,848	1,904	1,904	1,904	1,904	1,904	1,847	(57)	(0)	-	-	-	-	(57)	-3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.0%
2009	1,920	1,849	1,919	1,920	1,920	1,920	1,920	1,849	(70)	(0)	-	-	-	-	(70)	-3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.7%
2010	1,918	1,834	1,918	1,918	1,918	1,918	1,918	1,834	(84)	(0)	-	-	-	-	(84)	-4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	-4.4%
2011	1,949	1,853	1,949	1,949	1,949	1,949	1,949	1,852	(96)	(0)	-	-	-	-	(97)	-4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	-5.0%
2012	1,968	1,855	1,967	1,968	1,968	1,968	1,968	1,855	(113)	(1)	0	-	-	-	(114)	-5.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-5.8%
2013	1,991	1,854	1,989	1,991	1,991	1,991	1,991	1,852	(137)	(2)	0	-	-	-	(138)	-6.9%	-0.1%	0.0%	0.0%	0.0%	0.0%	-6.9%
2014	2,018	1,848	2,015	2,018	2,018	2,018	2,018	1,846	(170)	(2)	0	-	-	-	(172)	-8.4%	-0.1%	0.0%	0.0%	0.0%	0.0%	-8.5%
2015	2,091	1,889	2,088	2,092	2,091	2,091	2,091	1,887	(202)	(3)	0	-	-	-	(205)	-9.7%	-0.1%	0.0%	0.0%	0.0%	0.0%	-9.8%
2016	2,048	1,818	2,042	2,048	2,048	2,048	2,048	1,813	(230)	(5)	0	(0)	-	-	(234)	-11.2%	-0.2%	0.0%	0.0%	0.0%	0.0%	-11.4%
2017	2,030	1,775	2,022	2,031	2,022	2,030	2,030	1,759	(266)	(8)	1	(8)	-	-	(272)	-12.6%	-0.4%	0.0%	-0.4%	0.0%	0.0%	-13.4%
2018	2,126	1,845	2,112	2,127	2,102	2,126	2,126	1,807	(281)	(14)	1	(24)	(0)	-	(319)	-13.2%	-0.7%	0.0%	-1.4%	0.0%	0.0%	-15.0%
2019	2,134	1,827	2,110	2,136	2,105	2,134	2,134	1,774	(307)	(24)	1	(30)	(0)	(0)	(360)	-14.4%	-1.1%	0.1%	-1.4%	0.0%	0.0%	-16.9%
2020	2,148	1,818	2,115	2,150	2,125	2,148	2,148	1,762	(330)	(33)	2	(24)	(1)	(0)	(387)	-15.4%	-1.6%	0.1%	-1.1%	0.0%	0.0%	-18.0%
2021	2,150	1,802	2,107	2,153	2,124	2,149	2,150	1,734	(348)	(43)	2	(26)	(2)	(0)	(416)	-16.2%	-2.0%	0.1%	-1.2%	-0.1%	0.0%	-19.4%
2022	2,165	1,803	2,112	2,169	2,143	2,162	2,164	1,728	(362)	(53)	4	(22)	(3)	(1)	(436)	-16.7%	-2.4%	0.2%	-1.0%	-0.1%	0.0%	-20.2%
2023	2,171	1,796	2,110	2,177	2,143	2,165	2,169	1,707	(375)	(61)	6	(27)	(5)	(1)	(463)	-17.3%	-2.8%	0.3%	-1.3%	-0.2%	-0.1%	-21.3%
2024	2,305	1,919	2,235	2,315	2,270	2,298	2,304	1,813	(387)	(70)	9	(35)	(8)	(2)	(492)	-16.8%	-3.0%	0.4%	-1.5%	-0.3%	-0.1%	-21.3%
2025	2,262	1,863	2,178	2,276	2,222	2,251	2,260	1,741	(399)	(83)	14	(40)	(11)	(2)	(520)	-17.6%	-3.7%	0.6%	-1.8%	-0.5%	-0.1%	-23.0%
2026	2,274	1,864	2,175	2,295	2,230	2,260	2,272	1,723	(410)	(100)	20	(45)	(15)	(2)	(552)	-18.0%	-4.4%	0.9%	-2.0%	-0.6%	-0.1%	-24.3%
2027	2,286	1,864	2,170	2,314	2,241	2,267	2,283	1,708	(422)	(116)	28	(45)	(19)	(3)	(578)	-18.5%	-5.1%	1.2%	-2.0%	-0.8%	-0.1%	-25.3%
2028	2,297	1,863	2,166	2,334	2,251	2,274	2,294	1,695	(434)	(132)	37	(46)	(24)	(4)	(602)	-18.9%	-5.7%	1.6%	-2.0%	-1.0%	-0.2%	-26.2%
2029	2,308	1,863	2,162	2,355	2,261	2,279	2,303	1,685	(445)	(146)	47	(46)	(29)	(4)	(623)	-19.3%	-6.3%	2.1%	-2.0%	-1.3%	-0.2%	-27.0%
2030	2,319	1,863	2,160	2,379	2,272	2,284	2,313	1,678	(455)	(159)	60	(46)	(35)	(5)	(640)	-19.6%	-6.8%	2.6%	-2.0%	-1.5%	-0.2%	-27.6%
2031	2,329	1,864	2,160	2,403	2,282	2,288	2,323	1,675	(465)	(169)	75	(46)	(41)	(6)	(653)	-20.0%	-7.3%	3.2%	-2.0%	-1.8%	-0.3%	-28.1%
2032	2,339	1,864	2,161	2,430	2,293	2,291	2,332	1,676	(475)	(178)	91	(46)	(48)	(7)	(663)	-20.3%	-7.6%	3.9%	-2.0%	-2.0%	-0.3%	-28.3%
2033	2,349	1,866	2,165	2,458	2,303	2,294	2,341	1,681	(483)	(185)	109	(46)	(55)	(8)	(669)	-20.6%	-7.9%	4.6%	-2.0%	-2.3%	-0.3%	-28.5%
2034	2,357	1,865	2,168	2,485	2,311	2,295	2,348	1,686	(492)	(190)	128	(46)	(63)	(9)	(672)	-20.9%	-8.0%	5.4%	-2.0%	-2.7%	-0.4%	-28.5%
2035	2,369	1,869	2,175	2,517	2,322	2,298	2,359	1,696	(500)	(194)	148	(46)	(71)	(10)	(672)	-21.1%	-8.2%	6.3%	-2.0%	-3.0%	-0.4%	-28.4%
2036	2,378	1,870	2,181	2,548	2,331	2,298	2,367	1,707	(508)	(196)	170	(46)	(80)	(10)	(671)	-21.4%	-8.3%	7.2%	-1.9%	-3.4%	-0.4%	-28.2%
2037	2,388	1,873	2,190	2,581	2,342	2,299	2,377	1,721	(515)	(198)	193	(46)	(89)	(11)	(667)	-21.6%	-8.3%	8.1%	-1.9%	-3.7%	-0.5%	-27.9%
2038	2,398	1,874	2,198	2,616	2,351	2,298	2,386	1,735	(523)	(200)	218	(46)	(99)	(12)	(662)	-21.8%	-8.3%	9.1%	-1.9%	-4.1%	-0.5%	-27.6%
2039	2,407	1,877	2,206	2,651	2,361	2,298	2,395	1,752	(530)	(201)	244	(46)	(109)	(12)	(655)	-22.0%	-8.4%	10.1%	-1.9%	-4.5%	-0.5%	-27.2%
Annual Avg. 15 yr ('99 to '24)	1.2%	0.2%	1.0%	1.8%	1.1%	1.2%	1.2%	0.1%														
Annual Avg. 10 yr ('14 to '24)	1.3%	0.4%	1.0%	1.4%	1.2%	1.3%	1.3%	-0.2%														
Annual Avg. 5 yr ('19 to '24)	1.8%	1.0%	1.2%	1.6%	1.6%	1.6%	1.6%	0.4%														
Annual Avg. 5 yr ('24 to '29)	0.0%	-0.5%	-0.7%	0.9%	0.1%	0.2%	0.6%	1.6%														
Annual Avg. 10 yr ('24 to '34)	0.2%	-0.3%	-0.3%	0.7%	0.2%	0.0%	0.7%	0.7%														
Annual Avg. 15 yr ('24 to '39)	0.3%	-0.1%	-0.1%	0.9%	0.3%	0.0%	0.9%	-0.2%														

EE: Energy Efficiency (reduces load)
 PV: Solar - Photovoltaics (reduces load)
 EV: Electric Vehicles (ADDS to load)
 DR: Demand Response (Company only) (reduces load)
 ES: Energy Storage (reduces load)
 EH: Electric Heating Pump Cooling (reduces load)

**NECO
WINTER Peaks**

YEAR	Actuals		Normal 50-50		Extreme 10-90		Extreme 05-95		HDD_wtd
	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	ACTUAL
2008	1,305		1,329		1,368		1,379		40.0
2009	1,294	-0.8%	1,341	0.9%	1,383	1.1%	1,394	1.1%	35.0
2010	1,315	1.6%	1,275	-4.9%	1,321	-4.4%	1,335	-4.3%	53.1
2011	1,243	-5.5%	1,263	-0.9%	1,305	-1.2%	1,317	-1.3%	41.6
2012	1,320	6.2%	1,302	3.1%	1,344	3.0%	1,356	3.0%	51.9
2013	1,328	0.7%	1,336	2.6%	1,379	2.6%	1,391	2.6%	43.9
2014	1,275	-4.0%	1,239	-7.3%	1,286	-6.7%	1,299	-6.6%	52.2
2015	1,223	-4.1%	1,212	-2.1%	1,251	-2.7%	1,262	-2.8%	55.0
2016	1,239	1.3%	1,292	6.6%	1,340	7.0%	1,353	7.2%	35.9
2017	1,277	3.1%	1,218	-5.7%	1,281	-4.4%	1,298	-4.0%	53.8
2018	1,301	1.9%	1,263	3.6%	1,314	2.6%	1,329	2.4%	51.0
2019	1,183	-9.1%	1,203	-4.7%	1,259	-4.2%	1,274	-4.1%	42.4
2020	1,181	-0.1%	1,171	-2.6%	1,220	-3.1%	1,234	-3.2%	44.6
2021	1,208	2.3%	1,203	2.7%	1,250	2.5%	1,263	2.4%	43.8
2022	1,225	1.4%	1,303	8.3%	1,407	12.5%	1,436	13.7%	43.1
2023	1,143	-6.7%	1,181	-9.3%	1,271	-9.6%	1,296	-9.7%	41.9
2024			1,225	3.7%	1,317	3.6%	1,343	3.6%	
2025			1,231	0.5%	1,323	0.5%	1,349	0.5%	
2026			1,237	0.5%	1,329	0.5%	1,355	0.5%	
2027			1,246	0.7%	1,338	0.7%	1,364	0.7%	
2028			1,259	1.0%	1,350	0.9%	1,376	0.9%	
2029			1,276	1.4%	1,368	1.3%	1,394	1.3%	
2030			1,299	1.8%	1,391	1.7%	1,417	1.7%	
2031			1,324	1.9%	1,416	1.8%	1,442	1.8%	
2032			1,350	2.0%	1,442	1.9%	1,468	1.8%	
2033			1,379	2.1%	1,471	2.0%	1,497	2.0%	
2034			1,406	1.9%	1,498	1.8%	1,524	1.8%	
2035			1,439	2.3%	1,531	2.2%	1,557	2.2%	
2036			1,470	2.2%	1,562	2.0%	1,588	2.0%	
2037			1,505	2.4%	1,597	2.2%	1,623	2.2%	
2038			1,538	2.2%	1,630	2.1%	1,656	2.0%	
2039			1,567	1.8%	1,658	1.7%	1,684	1.7%	

Net *

Annual Avg. 15 yr ('08 to '23)	-0.8%	-0.5%	-0.4%	HDD_wtd
Annual Avg. 10 yr ('13 to '23)	-1.2%	-0.8%	-0.7%	NORMAL 45.2
Annual Avg. 5 yr ('18 to '23)	-1.3%	-0.7%	-0.5%	EXTREME 90/10 53.2
				EXTREME 95/5 55.4
Annual Avg. 5 yr ('23 to '28)	1.3%	1.2%	1.2%	
Annual Avg. 10 yr ('23 to '33)	1.6%	1.5%	1.4%	
Annual Avg. 15 yr ('23 to '39)	1.9%	1.7%	1.8%	

** impacts include energy efficiency, solar pv, electric vehicles, energy storage, electric heat pumps and company demand response (solar and demand response are zero at times of winter peak)
year is dec of year to feb of following year (i.e. year 2022 is dec 2022 to feb 2023)*

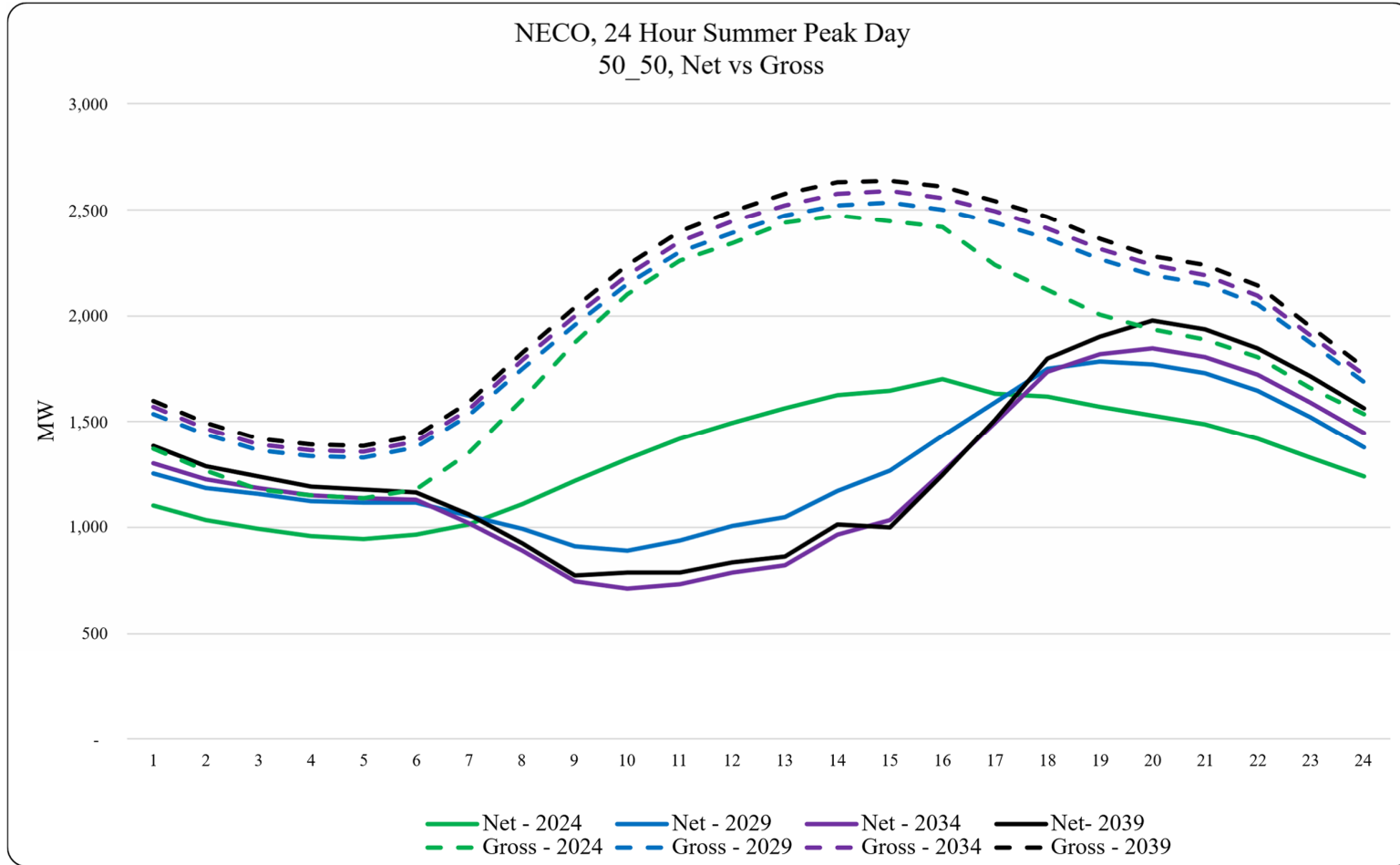
NECO	WINTER 50/50 Peaks (MW) (Gross and Net)								UNCERTAINTY IMPACTS *										Total Impact	EE % of 'Recon'd' Deliveries	PV % of 'Recon'd' Deliveries	EV % of 'Recon'd' Deliveries	DR % of 'Recon'd' Deliveries	ES % of 'Recon'd' Deliveries	EH % of 'Recon'd' Deliveries	Total % of 'Recon'd' Deliveries
	SYSTEM PEAK								PV						EV											
	Calendar Year	Gross	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Net	EE Forecast	PV Forecast	EV Forecast	DR Forecast	ES Forecast	EH Forecast	EE % of 'Recon'd' Deliveries	PV % of 'Recon'd' Deliveries	EV % of 'Recon'd' Deliveries								
2008	1,394	1,329	1,394	1,394	1,394	1,394	1,394	1,329	(66)	0	0	0	-	-	(65)	-4.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-4.7%				
2009	1,420	1,341	1,420	1,420	1,420	1,420	1,420	1,341	(79)	0	0	0	-	-	(79)	-5.6%	0.0%	0.0%	0.0%	0.0%	0.0%	-5.6%				
2010	1,365	1,275	1,365	1,365	1,365	1,365	1,365	1,275	(91)	0	0	0	-	-	(91)	-6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	-6.6%				
2011	1,368	1,263	1,368	1,368	1,368	1,368	1,368	1,263	(104)	0	0	0	-	-	(104)	-7.6%	0.0%	0.0%	0.0%	0.0%	0.0%	-7.6%				
2012	1,426	1,302	1,426	1,426	1,426	1,426	1,426	1,302	(124)	0	0	0	-	-	(123)	-8.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-8.7%				
2013	1,489	1,336	1,489	1,489	1,489	1,489	1,489	1,336	(153)	0	0	0	-	-	(153)	-10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-10.2%				
2014	1,436	1,238	1,436	1,436	1,436	1,436	1,436	1,239	(197)	0	0	0	-	-	(197)	-13.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-13.7%				
2015	1,438	1,212	1,438	1,438	1,438	1,438	1,438	1,212	(226)	0	1	-	-	-	(225)	-15.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-15.7%				
2016	1,544	1,291	1,544	1,544	1,544	1,544	1,544	1,292	(252)	0	1	-	-	-	(252)	-16.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-16.3%				
2017	1,498	1,217	1,498	1,498	1,498	1,498	1,498	1,218	(281)	0	1	-	-	-	(279)	-18.7%	0.0%	0.1%	0.0%	0.0%	0.0%	-18.7%				
2018	1,567	1,261	1,567	1,567	1,567	1,567	1,567	1,263	(306)	0	2	-	(0)	-	(305)	-19.5%	0.0%	0.1%	0.0%	0.0%	0.0%	-19.4%				
2019	1,529	1,198	1,529	1,531	1,528	1,528	1,531	1,203	(330)	0	2	-	(0)	3	(326)	-21.6%	0.0%	0.1%	0.0%	0.0%	0.2%	-21.3%				
2020	1,515	1,164	1,515	1,518	1,515	1,514	1,520	1,171	(351)	0	3	-	(1)	5	(344)	-23.2%	0.0%	0.2%	0.0%	-0.1%	0.3%	-22.7%				
2021	1,559	1,191	1,559	1,564	1,559	1,557	1,569	1,203	(368)	0	4	-	(2)	9	(357)	-23.6%	0.0%	0.3%	0.0%	-0.1%	0.6%	-22.9%				
2022	1,665	1,284	1,665	1,672	1,665	1,661	1,680	1,303	(381)	0	7	-	(4)	15	(362)	-22.9%	0.0%	0.4%	0.0%	-0.2%	0.9%	-21.8%				
2023	1,546	1,154	1,546	1,557	1,546	1,540	1,569	1,181	(392)	0	11	-	(6)	22	(365)	-25.3%	0.0%	0.7%	0.0%	-0.4%	1.5%	-23.6%				
2024	1,591	1,188	1,591	1,608	1,591	1,581	1,620	1,225	(403)	0	17	-	(10)	29	(366)	-25.3%	0.0%	1.1%	0.0%	-0.8%	1.8%	-23.0%				
2025	1,595	1,192	1,595	1,621	1,595	1,582	1,632	1,231	(413)	0	25	-	(13)	37	(364)	-25.9%	0.0%	1.6%	0.0%	-0.8%	2.3%	-22.8%				
2026	1,598	1,174	1,598	1,634	1,598	1,581	1,643	1,237	(424)	0	36	-	(17)	45	(361)	-26.5%	0.0%	2.2%	0.0%	-1.1%	2.8%	-22.6%				
2027	1,600	1,165	1,600	1,649	1,600	1,578	1,654	1,246	(435)	0	49	-	(22)	54	(354)	-27.2%	0.0%	3.0%	0.0%	-1.4%	3.4%	-22.1%				
2028	1,601	1,156	1,601	1,665	1,601	1,574	1,667	1,259	(445)	0	64	-	(27)	66	(342)	-27.8%	0.0%	4.0%	0.0%	-1.7%	4.1%	-21.4%				
2029	1,601	1,147	1,601	1,684	1,601	1,568	1,681	1,276	(455)	0	83	-	(33)	79	(326)	-28.4%	0.0%	5.2%	0.0%	-2.1%	4.9%	-20.3%				
2030	1,602	1,138	1,602	1,707	1,602	1,563	1,698	1,299	(464)	0	105	-	(39)	95	(303)	-29.0%	0.0%	6.5%	0.0%	-2.5%	6.0%	-18.9%				
2031	1,602	1,130	1,602	1,732	1,602	1,556	1,713	1,324	(473)	0	130	-	(46)	111	(278)	-29.5%	0.0%	8.1%	0.0%	-2.9%	6.9%	-17.4%				
2032	1,602	1,121	1,602	1,759	1,602	1,548	1,728	1,350	(481)	0	157	-	(54)	126	(251)	-30.0%	0.0%	9.8%	0.0%	-3.4%	7.9%	-15.7%				
2033	1,602	1,113	1,602	1,790	1,602	1,540	1,741	1,379	(489)	0	188	-	(62)	140	(223)	-30.6%	0.0%	11.7%	0.0%	-3.8%	8.7%	-13.9%				
2034	1,599	1,103	1,599	1,819	1,599	1,529	1,732	1,406	(496)	0	220	-	(70)	153	(193)	-31.0%	0.0%	13.8%	0.0%	-4.4%	9.6%	-12.1%				
2035	1,601	1,097	1,601	1,856	1,601	1,522	1,767	1,439	(503)	0	255	-	(79)	166	(162)	-31.4%	0.0%	15.9%	0.0%	-4.9%	10.4%	-10.1%				
2036	1,600	1,089	1,600	1,891	1,600	1,511	1,777	1,470	(510)	0	292	-	(89)	178	(129)	-31.9%	0.0%	18.2%	0.0%	-5.5%	11.1%	-8.1%				
2037	1,600	1,084	1,600	1,932	1,600	1,501	1,789	1,505	(517)	0	331	-	(99)	189	(95)	-32.3%	0.0%	20.7%	0.0%	-6.2%	11.8%	-5.9%				
2038	1,600	1,075	1,600	1,973	1,600	1,490	1,800	1,538	(525)	0	373	-	(109)	200	(62)	-32.8%	0.0%	23.3%	0.0%	-6.8%	12.5%	-3.8%				
2039	1,593	1,061	1,593	2,009	1,593	1,472	1,803	1,567	(532)	0	416	-	(121)	210	(26)	-33.4%	0.0%	26.1%	0.0%	-7.6%	13.2%	-1.7%				
Annual Avg. 15 yr ('08 to '23)	0.8%	-0.8%	0.8%	0.8%	0.8%	0.7%	0.9%	0.6%																		
Annual Avg. 10 yr ('13 to '23)	1.0%	-0.4%	1.0%	1.1%	1.0%	1.0%	1.2%	-0.1%																		
Annual Avg. 5 yr ('18 to '23)	0.8%	-0.2%	0.8%	1.0%	0.8%	0.7%	1.1%	0.4%																		
Annual Avg. 5 yr ('23 to '30)	0.1%	-0.7%	0.1%	0.5%	0.1%	0.2%	0.7%	0.8%																		
Annual Avg. 10 yr ('23 to '33)	0.1%	-0.7%	0.1%	0.5%	0.1%	0.3%	0.8%	1.4%																		
Annual Avg. 15 yr ('23 to '39)	0.2%	-0.8%	0.0%	1.5%	0.2%	0.5%	0.7%	1.7%																		

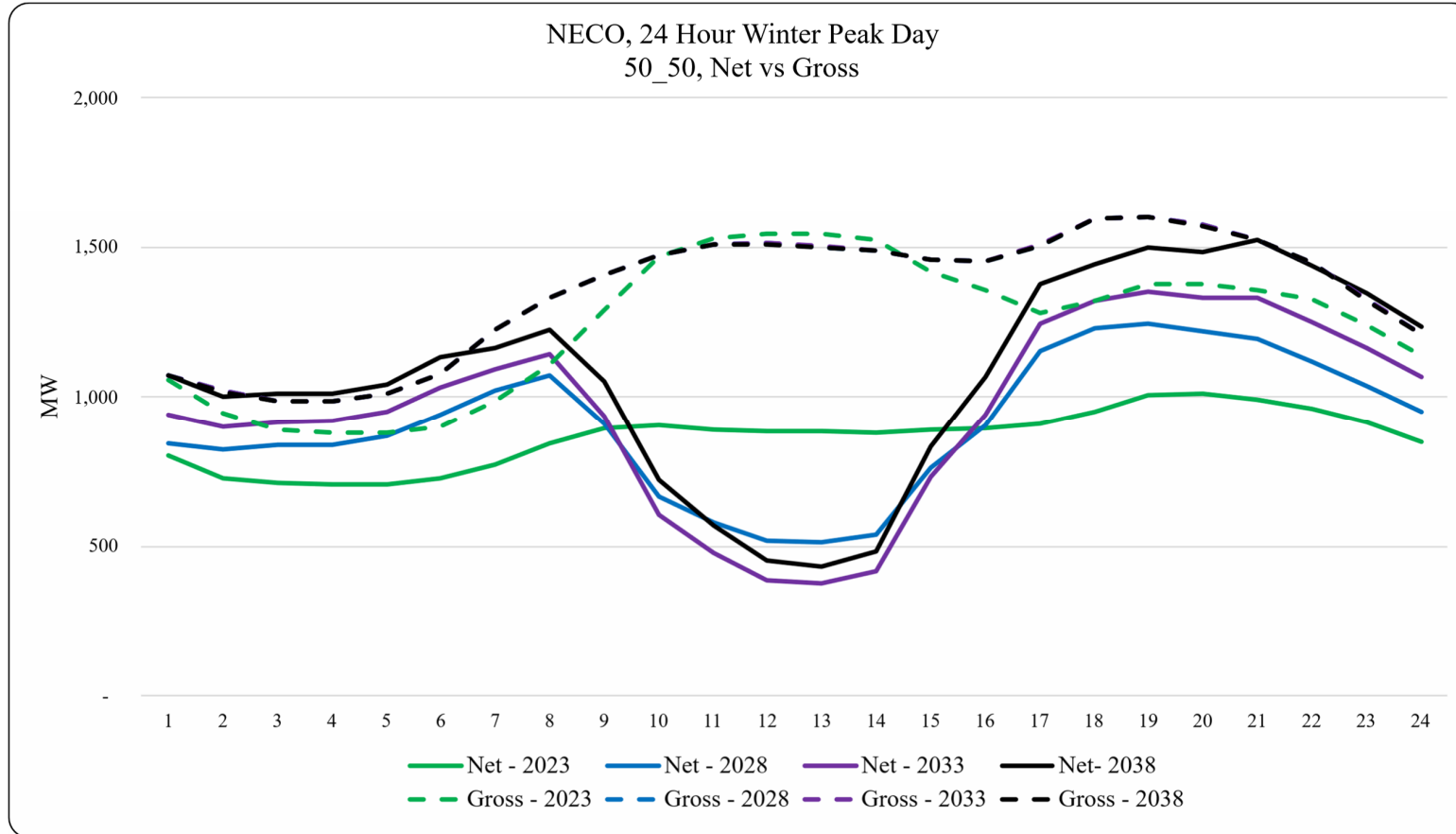
EE: Energy Efficiency (reduces load)
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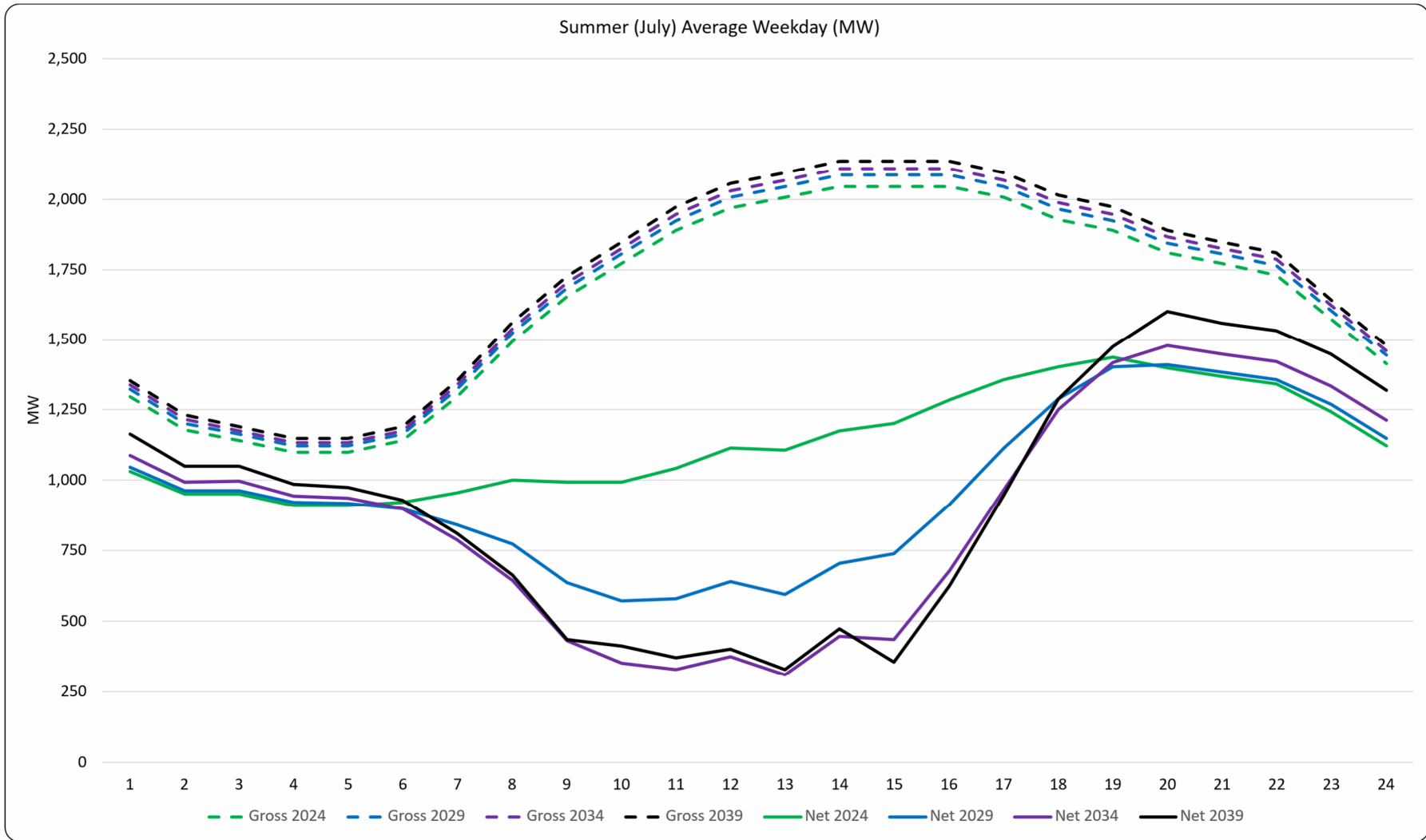
Appendix B: Historical Peaks Days and Hours

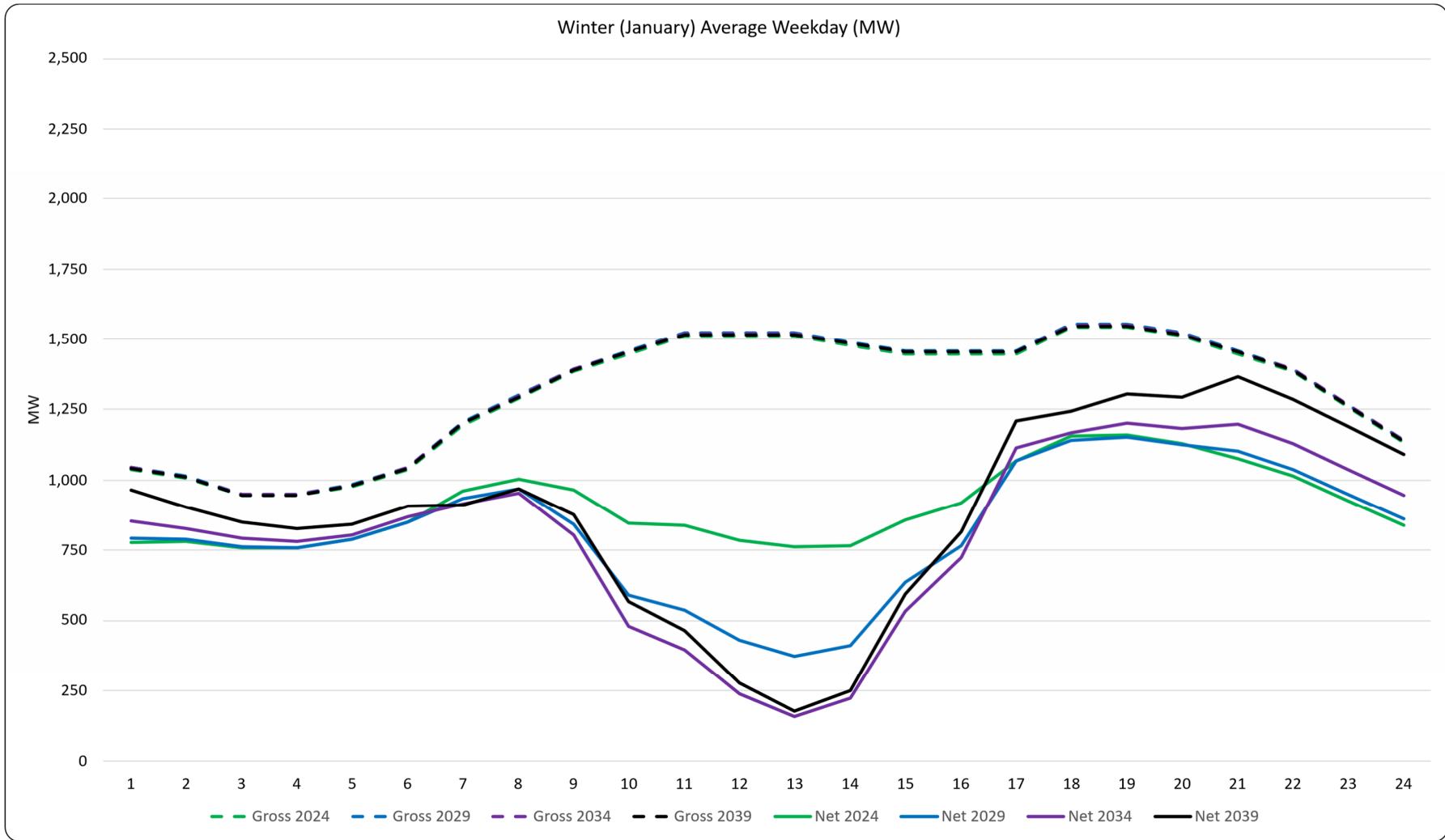
Summer			Winter		
Year	Date	Hour	Year	Date	Hour
2004	8/30/2004	15	2004	12/20/2004	19
2005	8/5/2005	15	2005	12/14/2005	18
2006	8/2/2006	15	2006	2/5/2007	19
2007	8/3/2007	15	2007	1/3/2008	19
2008	6/10/2008	15	2008	12/8/2008	18
2009	8/18/2009	15	2009	12/29/2009	19
2010	7/6/2010	15	2010	1/24/2011	19
2011	7/22/2011	16	2011	1/4/2012	18
2012	7/18/2012	15	2012	1/24/2013	19
2013	7/19/2013	15	2013	12/17/2013	18
2014	9/2/2014	16	2014	1/8/2015	18
2015	7/20/2015	15	2015	2/15/2016	19
2016	8/12/2016	16	2016	12/15/2016	18
2017	7/20/2017	16	2017	1/2/2018	19
2018	8/29/2018	17	2018	1/21/2019	18
2019	7/21/2019	18	2019	12/19/2019	19
2020	7/28/2020	15	2020	1/29/2021	19
2021	6/30/2021	16	2021	1/11/2022	18
2022	8/9/2022	15	2022	2/3/2023	19
2023	9/7/2023	16	2023	1/17/2024	20
2024	8/2/2024	16			

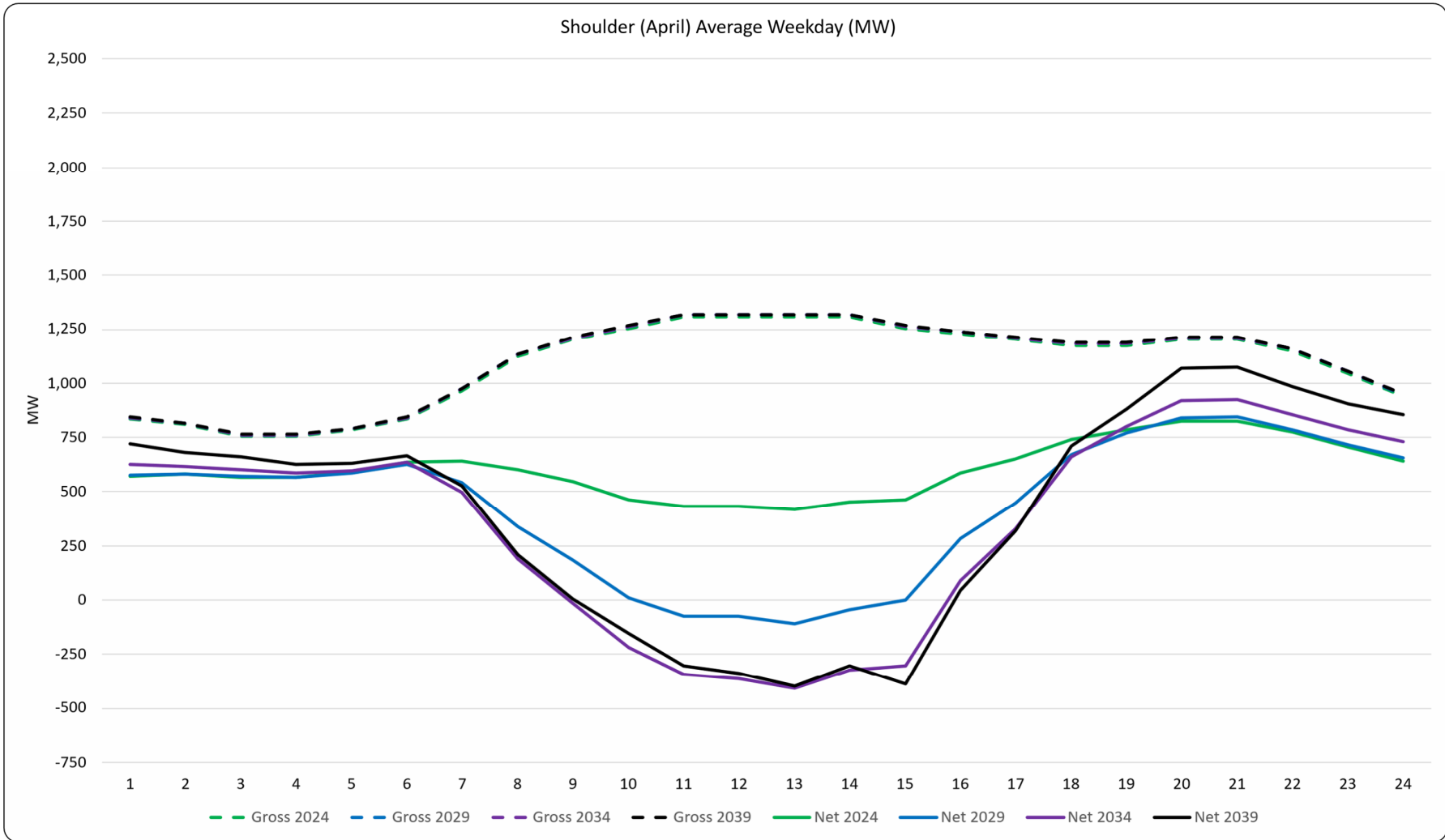
Appendix C: Load Shapes for Typical Day Types
(for Base Case)

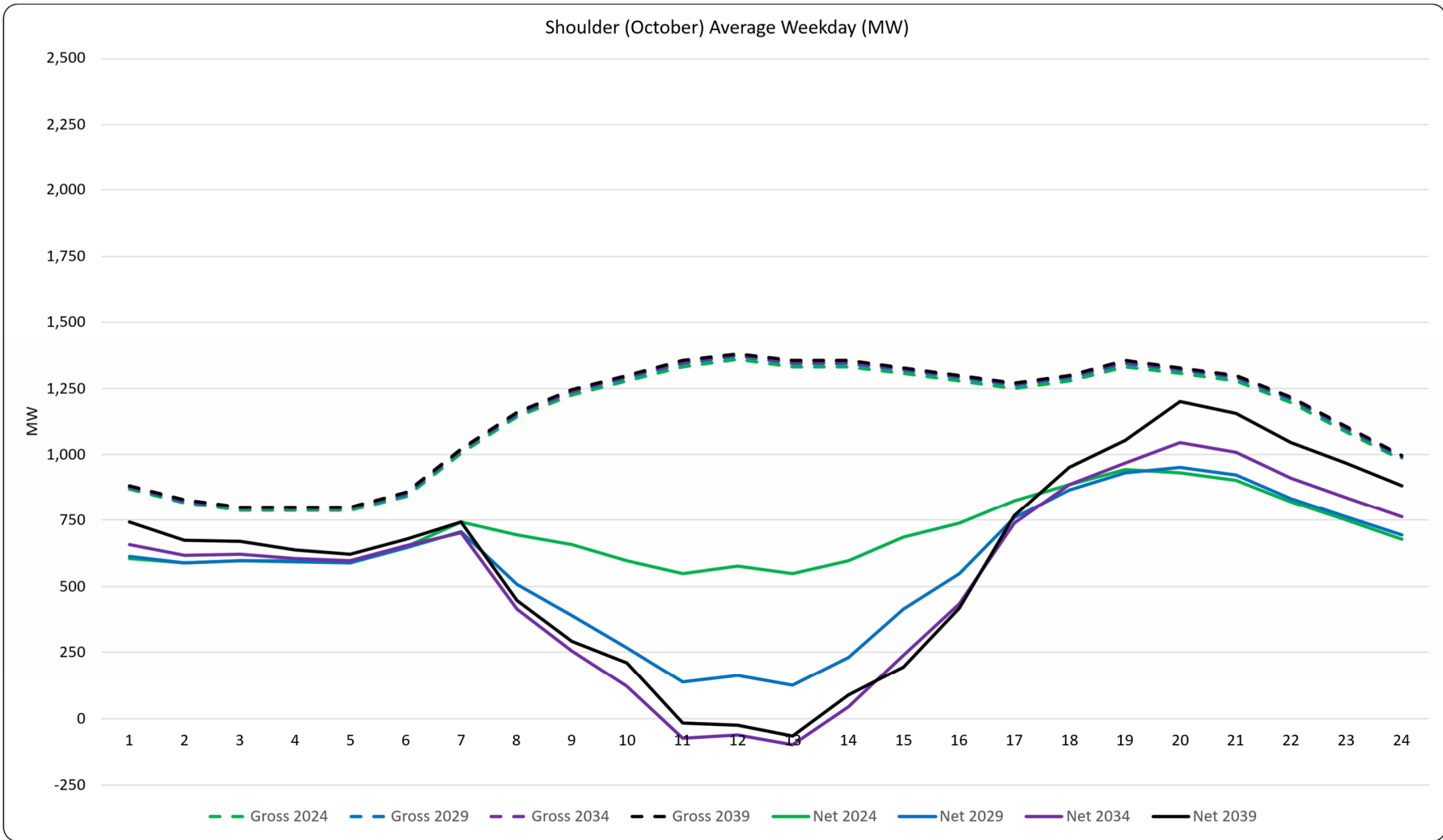


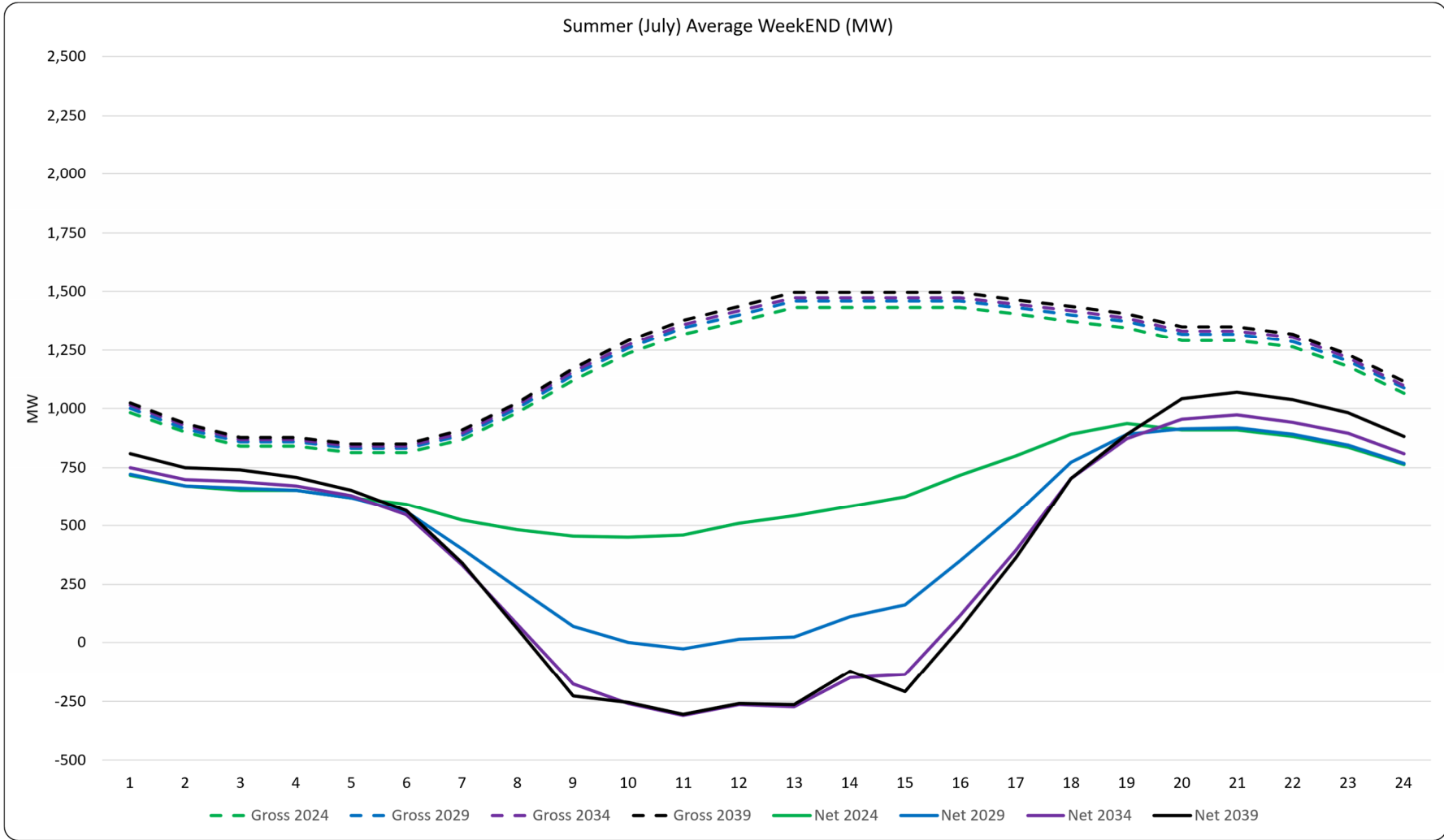


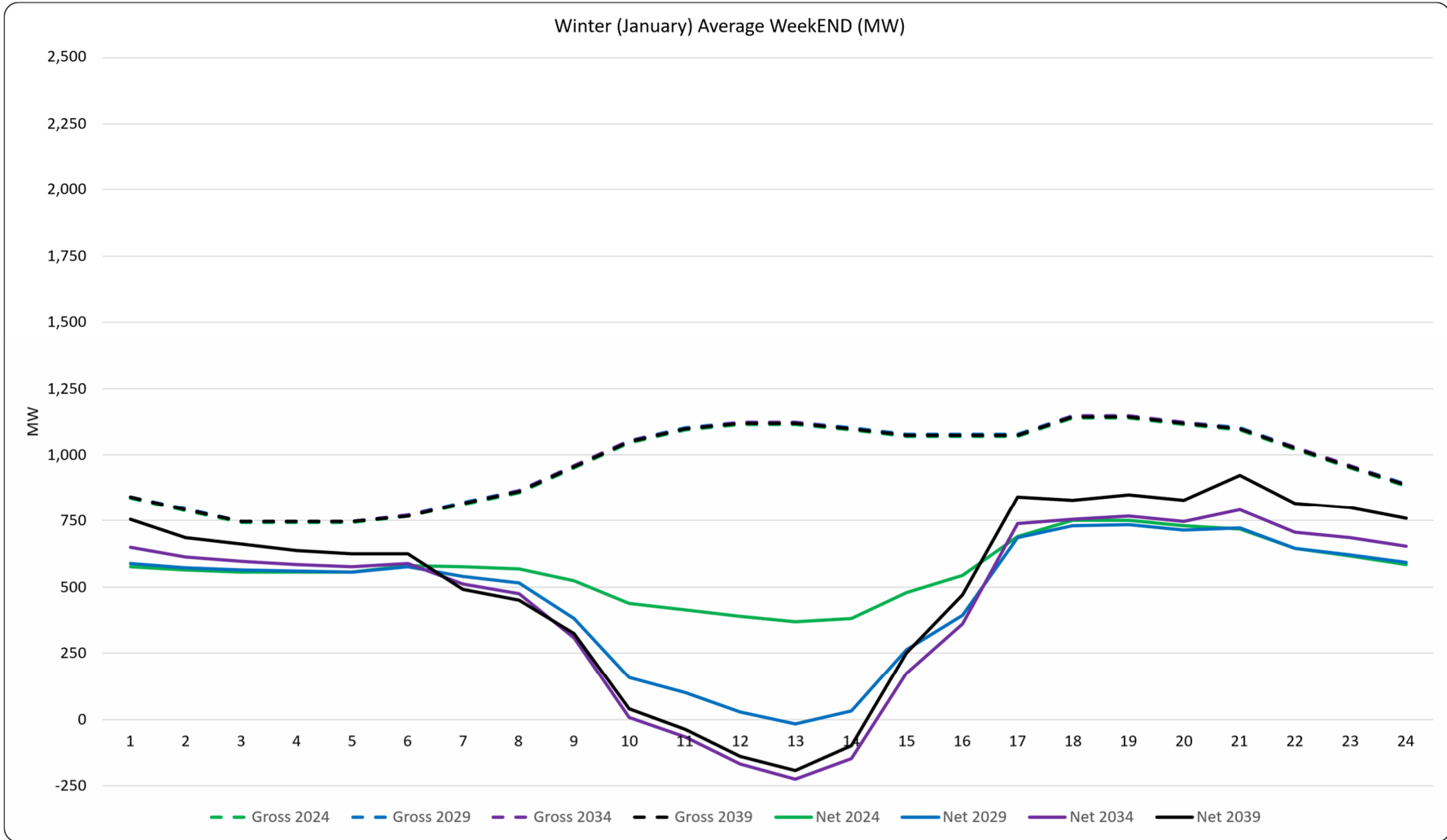


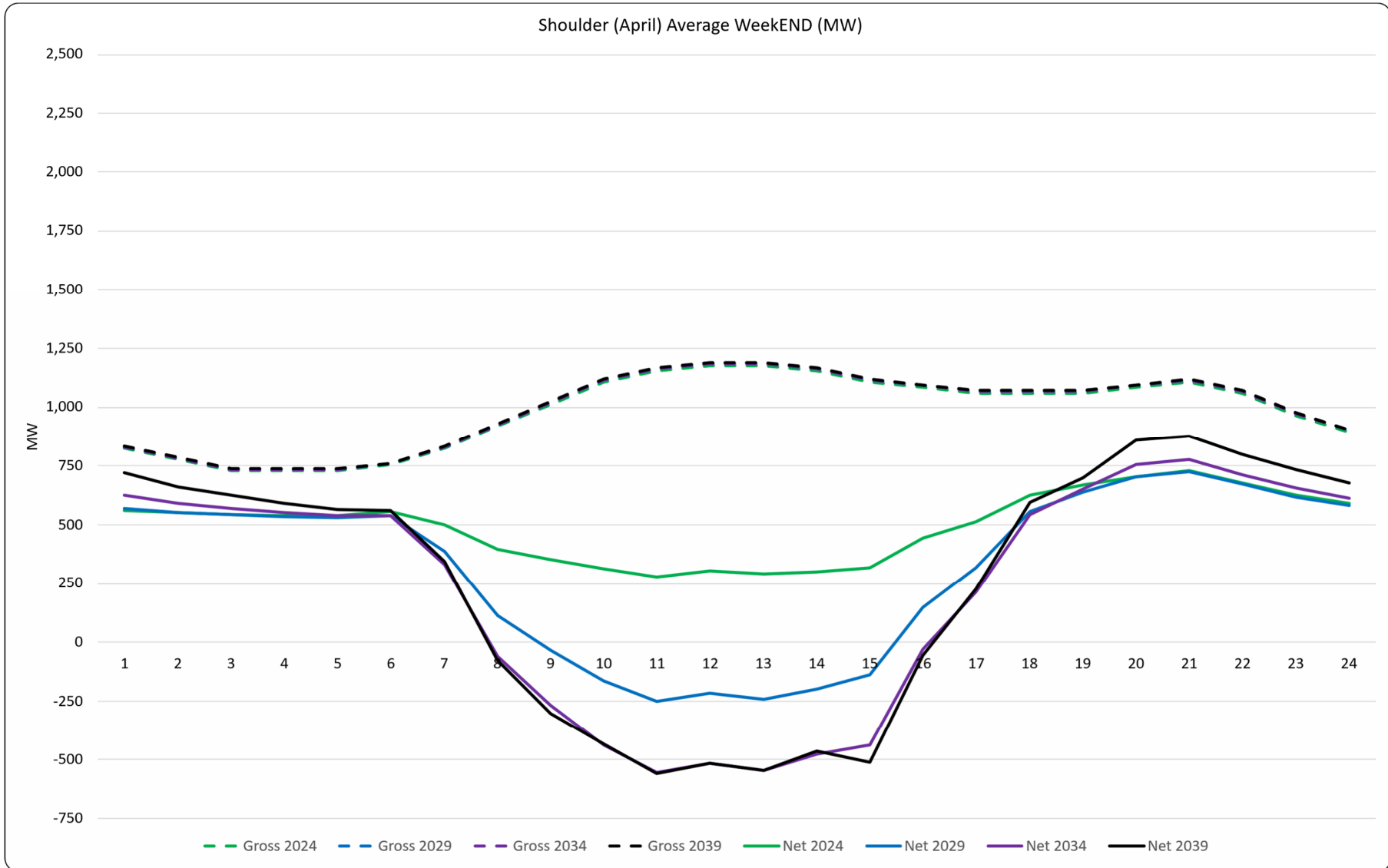


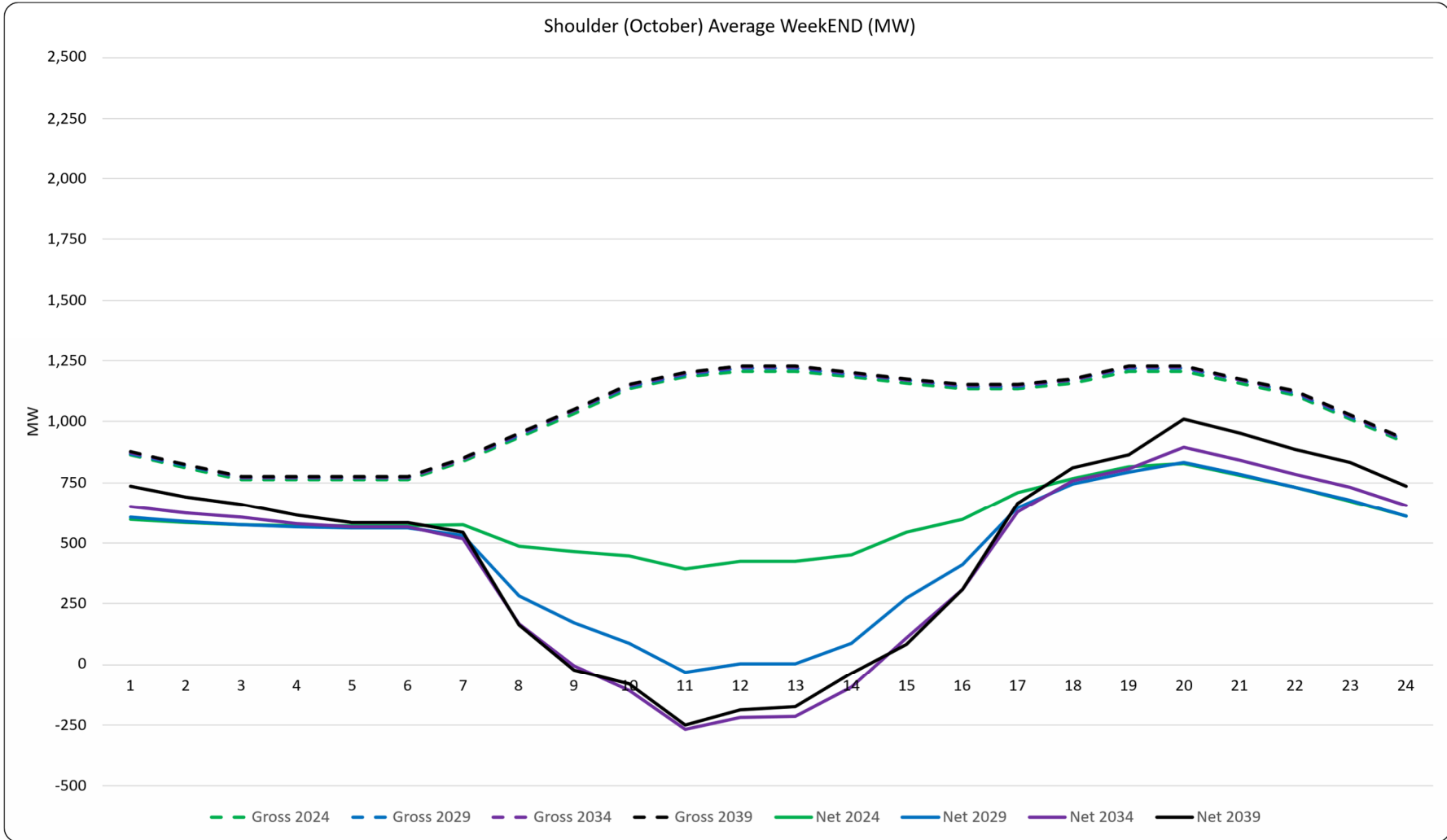








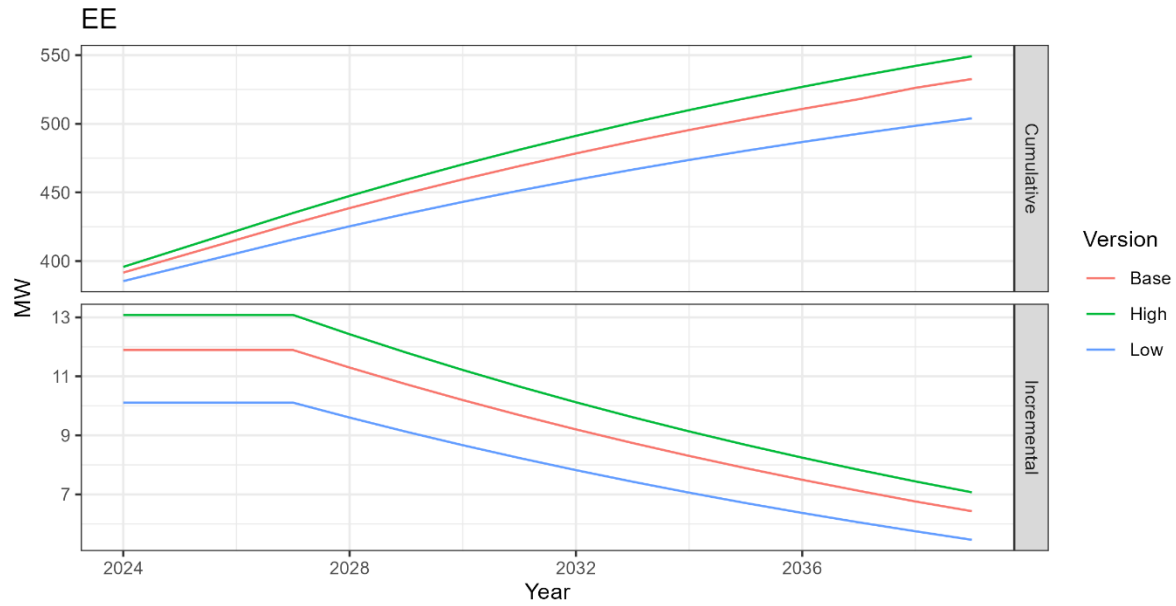




Appendix D: Key Uncertainty Scenarios Inputs

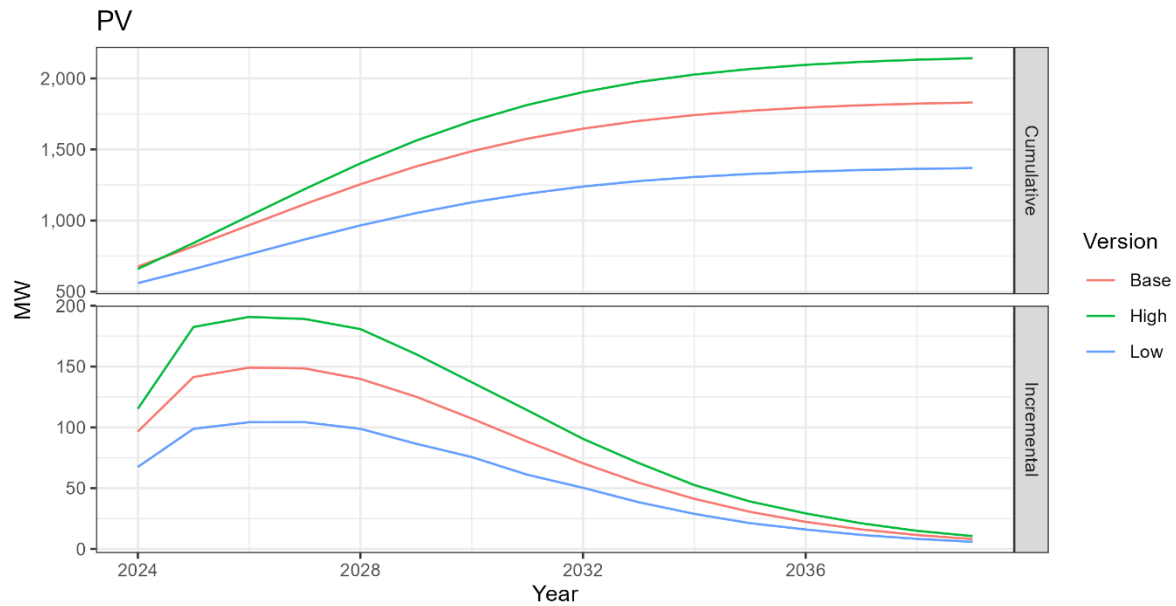
Energy Efficiency

Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	12	13	10	392	396	385
2025	12	13	10	403	409	395
2026	12	13	10	415	422	406
2027	12	13	10	427	435	416
2028	11	12	10	439	447	425
2029	11	12	9	449	459	434
2030	10	11	9	460	470	443
2031	10	11	8	469	481	451
2032	9	10	8	478	491	459
2033	9	10	7	487	501	467
2034	8	9	7	495	510	474
2035	8	9	7	503	519	480
2036	7	8	6	511	527	487
2037	7	8	6	518	535	493
2038	7	7	6	526	542	499
2039	6	7	5	533	549	504



Solar – PV

Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	96	115	67	677	659	560
2025	141	183	99	818	842	658
2026	149	191	104	967	1,032	763
2027	148	189	104	1,115	1,221	867
2028	140	181	99	1,255	1,402	966
2029	125	160	87	1,380	1,562	1,052
2030	107	137	76	1,488	1,699	1,128
2031	88	114	61	1,576	1,813	1,189
2032	70	91	50	1,646	1,904	1,239
2033	55	71	38	1,701	1,975	1,278
2034	41	53	29	1,742	2,027	1,306
2035	31	39	21	1,773	2,066	1,328
2036	22	29	16	1,795	2,096	1,344
2037	16	21	12	1,811	2,117	1,355
2038	11	15	8	1,823	2,132	1,364
2039	8	11	6	1,831	2,142	1,369

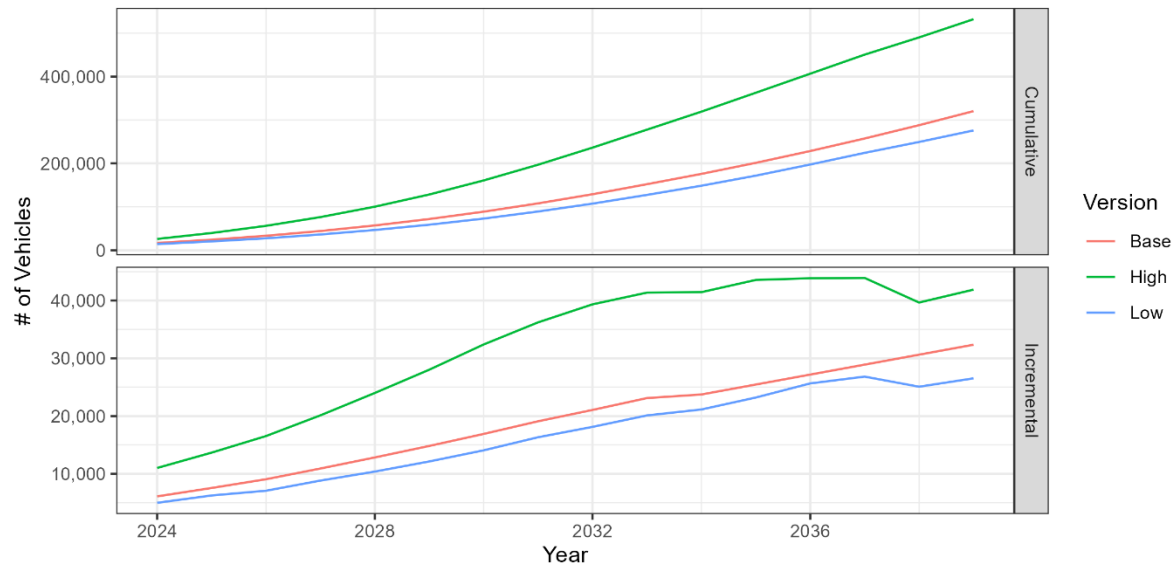


Electric Vehicles

Light Duty Vehicles

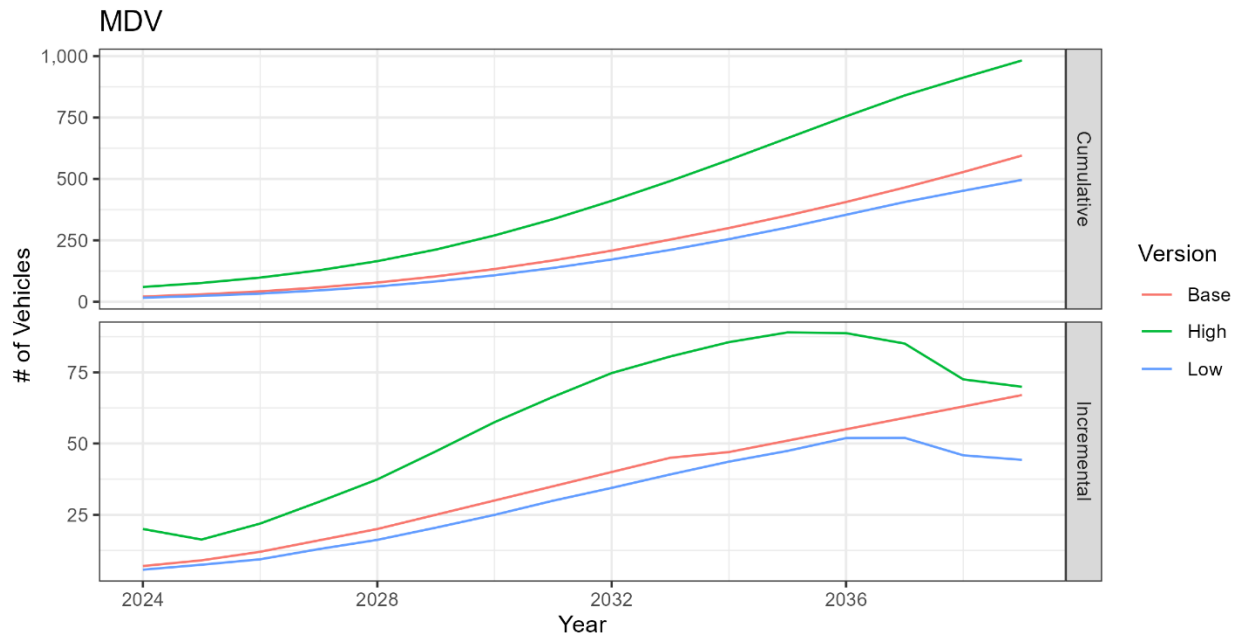
Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	6,090	11,010	4,978	16,703	25,985	14,103
2025	7,545	13,664	6,250	24,248	39,649	20,353
2026	9,060	16,534	7,069	33,308	56,183	27,422
2027	10,915	20,121	8,826	44,223	76,303	36,249
2028	12,832	23,996	10,387	57,055	100,300	46,635
2029	14,823	28,024	12,137	71,878	128,324	58,773
2030	16,905	32,393	14,065	88,783	160,716	72,838
2031	19,096	36,222	16,330	107,879	196,938	89,168
2032	21,058	39,340	18,127	128,937	236,278	107,295
2033	23,112	41,371	20,109	152,049	277,649	127,404
2034	23,733	41,448	21,137	175,782	319,098	148,541
2035	25,456	43,566	23,207	201,238	362,664	171,748
2036	27,179	43,854	25,648	228,417	406,517	197,396
2037	28,902	43,914	26,829	257,319	450,431	224,225
2038	30,625	39,655	25,080	287,945	490,085	249,305
2039	32,348	41,886	26,526	320,293	531,971	275,831

LDV



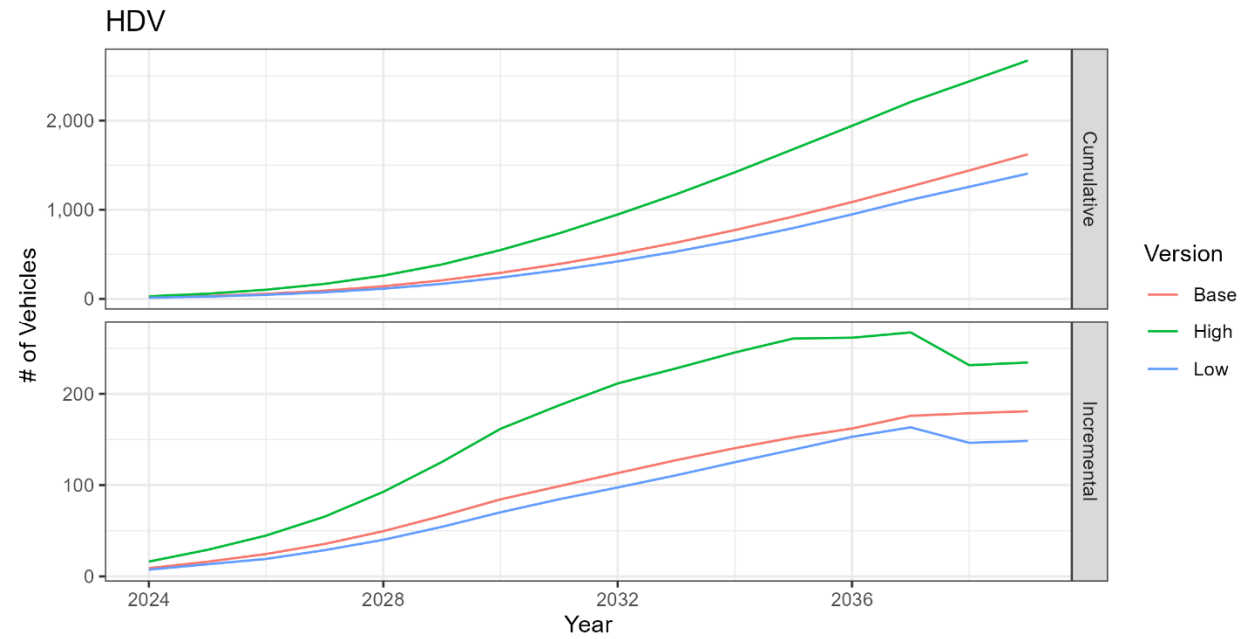
Medium Duty Vehicles

Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	7	20	6	21	60	16
2025	9	16	7	30	76	24
2026	12	22	9	42	98	33
2027	16	29	13	58	128	46
2028	20	37	16	78	165	62
2029	25	47	20	103	212	83
2030	30	57	25	133	270	108
2031	35	66	30	168	336	137
2032	40	75	34	208	411	172
2033	45	81	39	253	492	211
2034	47	86	44	300	577	255
2035	51	89	47	351	666	302
2036	55	89	52	406	755	354
2037	59	85	52	465	840	406
2038	63	73	46	528	912	452
2039	67	70	44	595	982	496



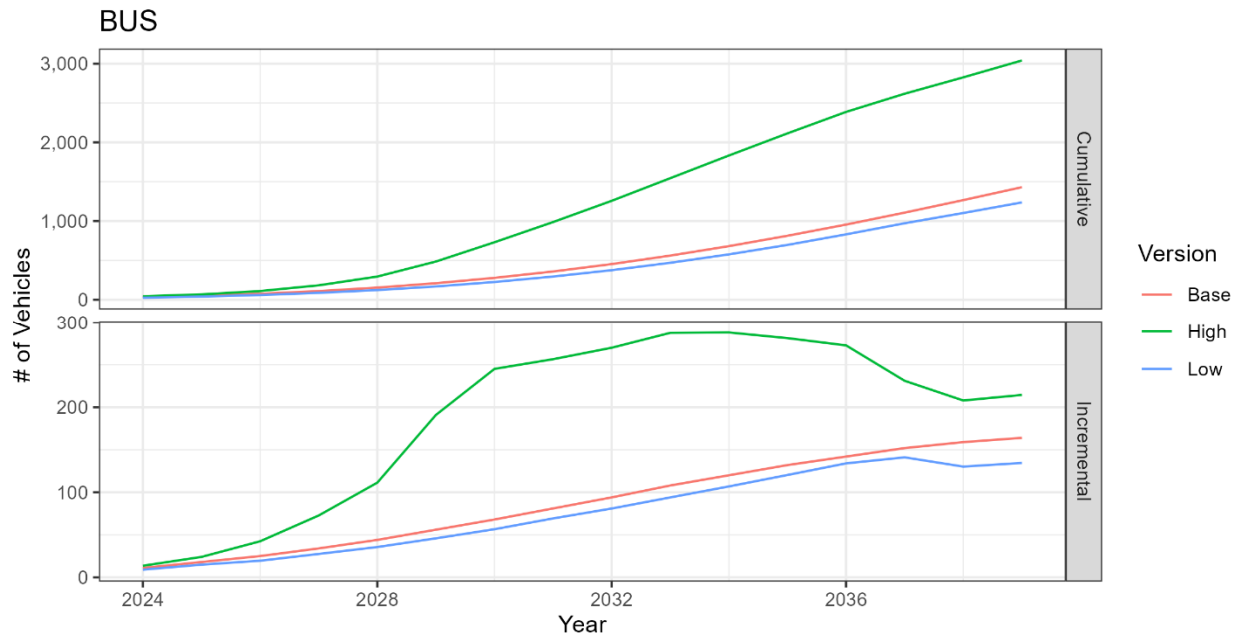
Heavy Duty Vehicles

Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	9	16	7	15	28	12
2025	16	29	13	31	57	25
2026	25	45	19	56	102	45
2027	36	65	29	91	168	73
2028	50	93	40	141	260	113
2029	66	125	54	207	386	168
2030	84	162	70	292	547	238
2031	99	187	85	391	735	322
2032	113	211	97	504	946	420
2033	127	228	111	631	1,174	531
2034	140	245	125	772	1,420	656
2035	152	261	139	924	1,680	795
2036	162	262	153	1,086	1,942	948
2037	176	267	163	1,262	2,209	1,111
2038	179	231	146	1,441	2,441	1,257
2039	181	234	148	1,622	2,675	1,406



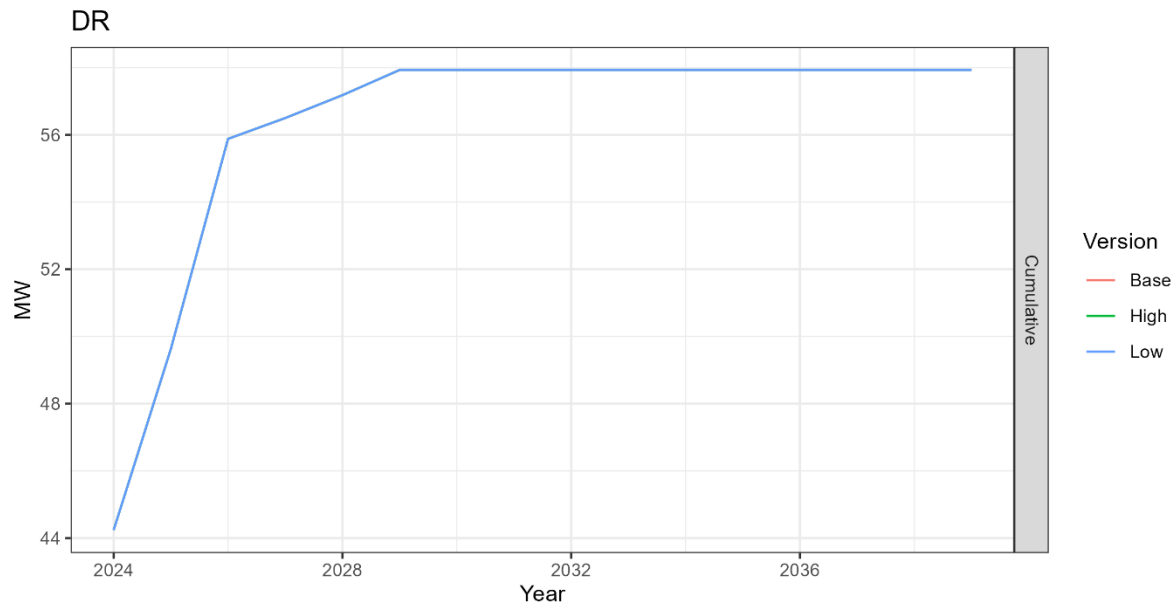
Bus

Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	11	14	9	33	44	25
2025	18	24	15	51	68	40
2026	25	42	20	76	110	60
2027	34	73	27	110	183	87
2028	44	111	36	154	294	123
2029	56	191	46	210	485	169
2030	68	245	57	278	731	225
2031	81	257	69	359	987	295
2032	94	270	81	453	1,257	376
2033	108	288	94	561	1,545	470
2034	120	288	107	681	1,833	576
2035	132	281	120	813	2,114	697
2036	142	273	134	955	2,387	831
2037	152	231	141	1,107	2,618	972
2038	159	208	130	1,266	2,826	1,102
2039	164	214	134	1,430	3,040	1,237



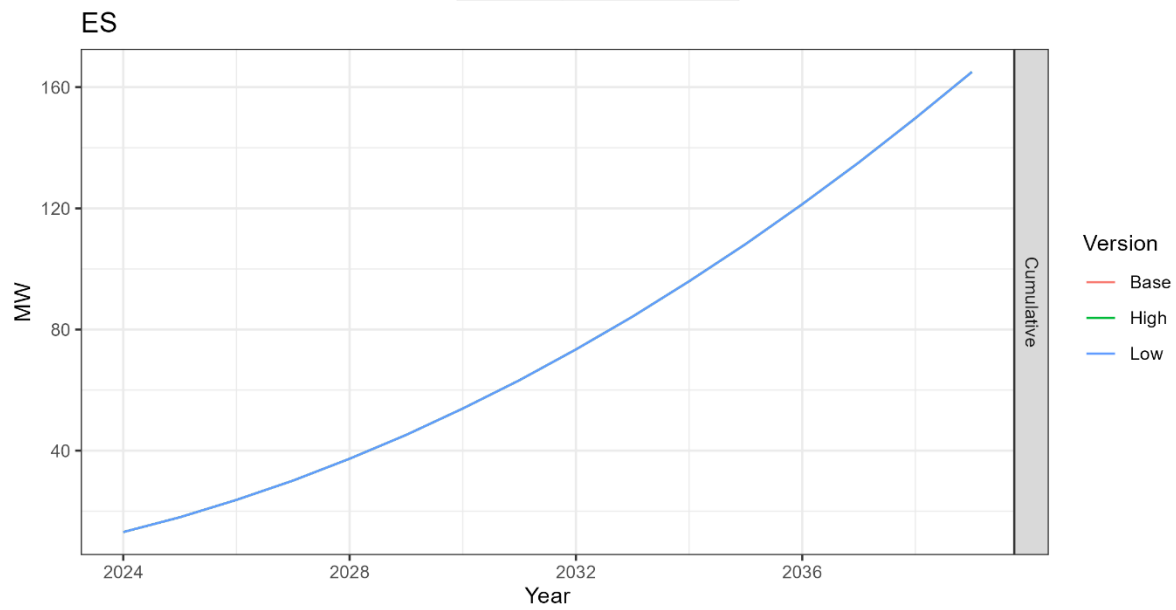
Demand Response

Year	Cumulative_Base
2024	44
2025	50
2026	56
2027	57
2028	57
2029	58
2030	58
2031	58
2032	58
2033	58
2034	58
2035	58
2036	58
2037	58
2038	58
2039	58



Energy Storage⁸

Year	Cumulative_Base
2024	13
2025	18
2026	24
2027	30
2028	37
2029	45
2030	54
2031	63
2032	73
2033	84
2034	96
2035	108
2036	121
2037	135
2038	150
2039	165

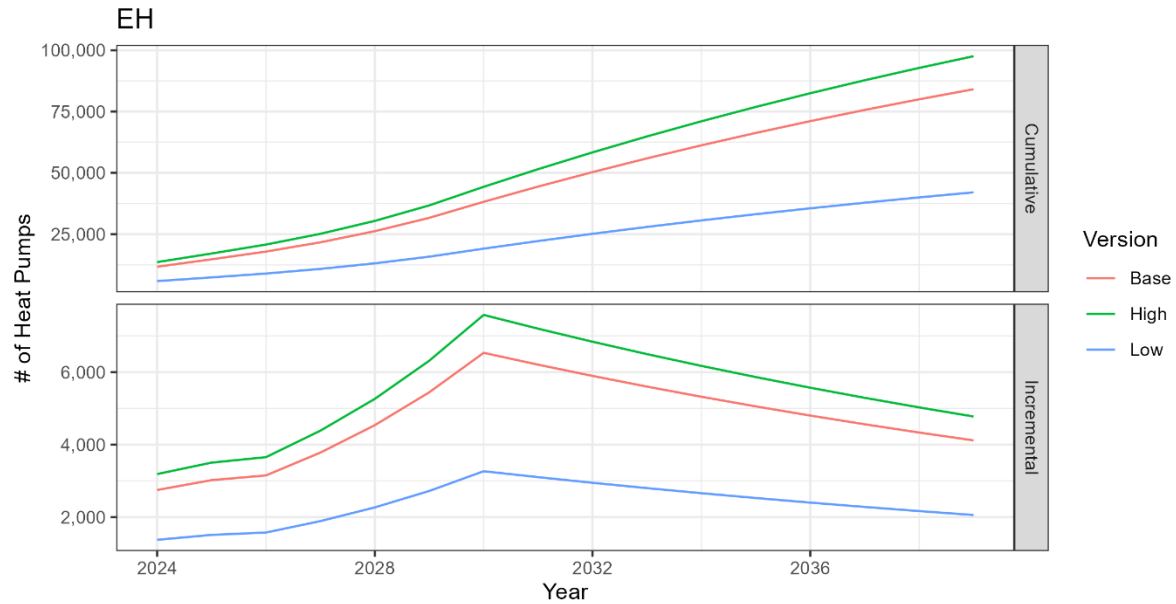


⁸ Another small amount of storage is being captured in the Company’s demand response program in Rhode Island.

Electric Heat Pumps

Number of Electric Heat Pumps

Year	Incremental_Base	Incremental_High	Incremental_Low	Cumulative_Base	Cumulative_High	Cumulative_Low
2024	2,749	3,189	1,375	11,730	13,607	5,865
2025	3,021	3,504	1,511	14,751	17,111	7,376
2026	3,151	3,655	1,576	17,902	20,766	8,951
2027	3,781	4,386	1,891	21,683	25,153	10,842
2028	4,537	5,263	2,269	26,221	30,416	13,110
2029	5,445	6,316	2,722	31,666	36,732	15,833
2030	6,534	7,579	3,267	38,199	44,311	19,100
2031	6,207	7,200	3,104	44,407	51,512	22,203
2032	5,897	6,840	2,948	50,304	58,352	25,152
2033	5,602	6,498	2,801	55,906	64,850	27,953
2034	5,322	6,173	2,661	61,227	71,024	30,614
2035	5,056	5,865	2,528	66,283	76,889	33,142
2036	4,803	5,572	2,402	71,086	82,460	35,543
2037	4,563	5,293	2,281	75,649	87,753	37,825
2038	4,335	5,028	2,167	79,984	92,781	39,992
2039	4,118	4,777	2,059	84,102	97,558	42,051



Appendix E: Key Uncertainty Scenarios Development

Energy Efficiency

For Rhode Island, measure lives were incorporated into the forecast, which assumes that 10% of savings expire after the usable life of the device. Additionally, we are not considering equipment being replaced without going through the programs.

- Planned Values are used for 2024-2026 for all programs.
- For all programs, it is assumed program growth stays constant until 2031 and then there is a steady decline from 2032 through the end of the forecast period.
- High case assumes 10% higher than base case.
- Low case assumes 20% lower than base case.

Solar-PV

Base

- The 2024 forecast is based on historical numbers, more specifically the year-to-date interconnected MW, going back to 2016. We are currently seeing a reduction in both the number of complex applications (>25 kW), as well as simplified applications (<=25 kW). Application volumes decreased by approximately 30% from CY22 – 23.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation/inception of new/existing public policies.

High

- The near term (2024-2027), we see a potential reduction in inflationary costs that were attributed to the pandemic, in turn generating more viable projects. In addition, additional incentives through the Inflation Reduction Act (IRA) could potentially generate more demand for solar installations.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation/inception of new/existing public policies.

Low

- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation/inception of new/existing public policies.
- Increased speculative behavior around economic factors, such as interest rates and inflation could continue potentially continue to limit growth in the renewable distributed generation sector.

Electric Vehicles

Light-duty Vehicles

Base

- The base case is developed from Bloomberg’s 2021 Long-term Electric Vehicle Outlook (BNEF-2021). The EV sales share of light-duty vehicle sales is assumed to follow BNEF-2021 estimates and vehicle scrap is also assumed based on BNEF-2021’s estimates to develop the net EV in-operation numbers. In this case, the zero-emission vehicle sales share of LDS sales is assumed to achieve 31% by 2030 and 59% by 2035.

High

- The high case assumes an accelerated full-electrification scenario in which the zero-emission vehicle sales share of LDV sales is assumed to achieve 64% by 2030 and 100% by 2035. It also aligns with BNEF-2021’s “Net Zero” scenario and California drafted ACC-II regulations.

Low

- The low case is a moderate transportation electrification developed from BNEF-2021. In this case, the zero-emission vehicle sales share of LDV sales is assumed to reach 25% by 2030 and 64% by 2035.

Medium-duty Vehicles, Heavy-duty Vehicles, and E-buses

The adoption of medium-duty EV, heavy-duty EV, and E-buses is based on BNEF-2021 estimates and the MOU policy targets. Two cases were developed for the adoption forecast. The base case is a market-driven case of adoption where MDEV, HDEV, and E-buses are estimated to reach 16%, 17%, and 26% of vehicles, respectively, by the end of the forecast period. The high case is an accelerated electrification scenario where vehicles shares reach 38%, 20%, and 63%, respectively.

Demand Response

For the short term (i.e. until 2024), the approved Company targets from the SME Program Administrator for DR is used as the projection. Post year 2024, no additional incremental MW are added except for batteries. It is assumed that the program’s market potential is at its maximum and the projections are held constant through year 2040. For batteries, a 10% increase is assumed until 2030 and then projections are held constant through the end of the forecast period.

Energy Storage

Currently there is minimal historical data in regard to the number of interconnected energy storage applications, as well as interconnected MW. Therefore, the forecast was developed assuming linear growth over the next several years.

Electric Heat Pumps

- 2024-2026 are planned values.
- For base, a 20% annual increase is assumed through 2030 with the growth decreasing by 5% each year after. The growth assumed from 2024-3031 is due to state and federal funding through the OER and the HEERA program.
- For high, increases with high growth until 2030 and then begins to decrease in 2031 due to market saturation.
- For low, assumes 20% lower than base case.

CLF 2-3
Seasonal Heat Pump Rate Design

Request:

Please provide representative feeder-level hourly load data (8760 profile) for representative feeder archetypes (e.g., urban/coastal/rural) used for internal planning for 2021-2025.

Response:

After consultation with the Company, CLF has withdrawn this request, in part, due to the security risk posed by analyzing detailed data with artificial intelligence tools.

CLF 2-4
Seasonal Heat Pump Rate Design

Request:

Please provide latest transformer table, as provided to the Division in the most recent Infrastructure, Safety and Reliability docket, including recent transformer winter/summer peaks and ratings and linkages to feeders/substations.

Response:

Please see the Company's response to CLF 2-2.

CLF 2-5
Seasonal Heat Pump Rate Design

Request:

Please provide representative substation-level hourly load data (8760 profile).

Response:

After consultation with the Company, CLF has withdrawn this request, in part, due to the security risk posed by analyzing detailed data with artificial intelligence tools.

CLF 2-6
Seasonal Heat Pump Rate Design

Request:

Please provide a sub-transmission table analogous to the feeder/transformer tables described in CLF 2-2 and CLF 2-4 above. This would include sub-transmission elements or “areas” with characteristics needed to approximate headroom/capacity, including recent transformer winter and summer peaks and rating and substation linkages.

Response:

Attachment CLF 2-6 contains sub-transmission line peak tables.

Winter peaks have not been provided, as the system is currently summer limited and is expected to remain summer limited into the late 2030s. Additional details are provided in the Company's response to CLF 2-2.

Line No.	Study Area (a)	Circuit (b)	Voltage (kV) (c)	Terminal Substation - From (d)	Terminal Substation - To (e)	Rating (MVA)	Rating (MVA)	Actual Load	Actual Load	Actual Load	Actual Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load	Projected Load
						SN (f)	SE (g)	2021 MVA (h)	2022 MVA (i)	2023 MVA (j)	2024 MVA (k)	2025 MVA (l)	2026 MVA (m)	2027 MVA (n)	2028 MVA (o)	2029 MVA (p)	2030 MVA (q)	2031 MVA (r)	2032 MVA (s)	2033 MVA (t)	2034 MVA (u)	2035 MVA (v)
1	Central RI East	2222	23	Drumrock	Warwick 52	20.52	20.52	10.52	11.11	9.73	9.74	10.31	10.25	10.21	10.17	10.15	10.14	10.15	10.18	10.22	10.29	10.36
2	Central RI East	2224	23	Drumrock Sub	Industrial Customers	14.54	14.54	1.12	1.01	1.02	0.93	1.00	0.99	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.99	1.00
3	Central RI East	2233	23	Sockanosset Sub	Aubrun / Lakewood	35.46	35.46	15.73	15.30	12.43	12.57	12.96	12.87	12.81	12.75	12.72	12.70	12.72	12.76	12.81	12.89	12.98
4	Central RI East	2260	23	Franklin Sq	Lakewood	9.60	12.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Central RI East	2262	23	Drumrock 14	Apponaug 3 / Warwick 52	25.70	25.70	13.90	14.40	13.69	13.61	14.58	14.47	14.40	14.34	14.30	14.28	14.30	14.35	14.41	14.50	14.59
6	Central RI East	2264	23	Drumrock 14	Apponaug 3	20.52	20.52	6.34	7.30	8.31	8.31	8.90	8.83	8.79	8.75	8.73	8.72	8.73	8.76	8.80	8.85	8.91
7	Central RI West	2230	23	Drumrock 14	Anthony / Hope	44.02	44.02	13.50	13.30	11.83	13.91	14.79	14.72	14.65	14.61	14.60	14.61	14.66	14.72	14.82	14.91	15.03
8	Central RI West	2232	23	Drumrock 14	Coventry / Hope	35.46	44.02	6.96	7.50	7.43	11.19	11.90	11.84	11.79	11.76	11.74	11.76	11.79	11.85	11.92	12.00	12.09
9	Central RI West	2266	23	Drumrock 14	Natick 29 / Warwick Mall	35.46	35.46	16.34	17.30	15.45	14.34	15.04	14.97	14.90	14.86	14.85	14.86	14.91	14.97	15.07	15.17	15.29
10	Central RI West	3309	34.5	Kent County 22	Tiogue Ave / Hopkins Hill	39.74	48.40	17.66	18.40	17.10	28.03	29.80	29.66	29.53	29.45	29.42	29.45	29.54	29.67	29.86	30.05	30.29
11	Central RI West	3310	34.5	Kent County 22	Hopkins Hill	53.20	53.20	17.40	17.90	16.97	20.33	21.61	21.51	21.42	21.36	21.34	21.36	21.43	21.52	21.66	21.80	21.97
12	Central RI West	3311	34.5	Kent County 22	Hopkins Hill / Division St	53.18	53.20	36.83	37.90	37.15	33.47	38.42	38.23	38.07	37.96	37.92	37.96	38.09	38.25	38.50	38.74	39.05
13	Central RI West	3312	34.5	Kent County 22	Division St / Lafayette	53.18	53.18	29.51	28.30	33.36	27.13	28.84	28.70	28.58	28.50	28.47	28.50	28.60	28.72	28.90	29.09	29.32
14	East Bay	2242	23	Phillipsdale 20	Waterman Ave	35.06	35.06	7.56	8.17	9.20	9.20	9.66	9.59	9.57	9.56	9.60	9.63	9.67	9.71	9.75	9.85	9.95
15	East Bay	2243	23	Phillipsdale 20	Industrial Customers	35.06	35.06	3.85	3.85	3.85	3.85	4.12	4.09	4.08	4.08	4.10	4.11	4.13	4.15	4.16	4.20	4.25
16	East Bay	2267	23	Mink Street	Waterman Ave	12.00	12.00	4.60	4.60	4.60	4.60	4.93	4.89	4.88	4.88	4.90	4.91	4.93	4.95	4.97	5.02	5.07
17	East Bay	2291	23	Warren Yard	Barrington / Kent Corners	34.00	43.70	24.63	23.60	21.60	23.04	24.66	24.48	24.43	24.41	24.51	24.60	24.70	24.80	24.90	25.15	25.40
18	East Bay	2295	23	Warren Substation	Bristol Substation	26.09	32.40	9.60	9.32	9.50	9.01	10.00	11.09	11.07	13.77	13.82	13.88	13.93	13.99	14.05	14.19	14.33
19	Newport	37K24	23	Jepson	Gate 2	79.40	101.60	18.09	21.30	20.40	20.80	22.27	22.12	22.01	21.92	21.85	21.83	21.85	21.92	22.03	22.18	22.32
20	Newport	37K21	23	Jepson	West Howard	19.32	23.70	3.77	10.40	10.50	9.20	9.85	9.78	9.73	9.69	9.67	9.66	9.67	9.69	9.74	9.81	9.87
21	Newport	37K22	23	Jepson	Hospital / Merton / West Howard	19.32	23.70	8.80	2.80	2.80	2.80	3.00	2.98	2.96	2.95	2.94	2.94	2.94	2.94	2.97	2.99	3.00
22	Newport	38K21	23	Gate 2	Kingston	22.91	22.91	13.61	13.60	13.60	13.30	14.24	14.14	14.07	14.02	13.97	13.96	13.97	14.02	14.09	14.18	14.27
23	Newport	54K21	23	West Howard VCB 5421	Harrison	10.64	12.63	3.06	3.06	3.00	3.00	2.90	2.88	2.87	2.85	2.85	2.84	2.85	2.85	2.87	2.89	2.91
24	Newport	54K23	23	West Howard 154K23	Harrison	8.37	10.04	3.77	3.77	5.50	5.50	5.10	5.06	5.04	5.02	5.00	5.00	5.00	5.02	5.04	5.08	5.11
25	Newport	38K23	23	Gate 2	West Howard / Clarke St / Eldred	26.60	32.00	15.98	20.70	20.20	20.20	20.20	20.06	19.96	19.88	19.82	19.80	19.82	19.88	19.98	20.12	20.24
26	North Central RI	2211	23	Johnston Sub.	Mannton	35.46	35.46	23.20	23.50	21.90	21.11	22.61	22.44	22.33	22.24	22.18	22.15	22.18	22.25	22.35	22.49	22.63
27	North Central RI	2219	23	Wolf Hill Substation	Centredale	20.52	20.52	9.40	9.00	8.52	8.39	8.99	8.92	8.88	8.68	8.66	8.65	8.66	8.69	8.73	8.78	8.84
28	North Central RI	2221	23	Wolf Hill Substation	Chopmist	20.50	20.50	19.00	18.20	17.11	17.96	19.24	19.09	19.00	18.92	18.87	18.85	18.87	18.93	19.01	19.13	19.26
29	North Central RI	2226	23	Johnston Substation	Knightsville	21.47	24.62	14.70	14.40	10.35	4.92	7.87	7.81	7.77	14.21	14.17	14.16	14.17	14.22	14.28	14.37	14.46
30	North Central RI	2227	23	Johnston Substation	West Greenville / Chopmist	35.00	35.00	17.60	22.50	16.25	14.09	15.09	14.98	14.91	14.84	14.80	14.79	14.80	14.85	14.92	15.01	15.11
31	North Central RI	2228	23	Johnston Substation	Hope	26.50	33.70	12.10	11.60	10.22	13.57	14.53	14.43	21.66	21.64	21.58	21.56	21.58	21.65	21.74	21.88	22.02
32	North Central RI	2202	23	Johnston Sub.	Industrial Customers	14.00	14.30	0.30	0.30	0.67	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
33	Providence	1102	11	South St. Sub	South St 4kV	7.50	10.00	3.10	3.20	3.13	5.40	5.78	5.74	5.73	5.72	5.75	5.77	5.79	5.82	5.84	5.90	5.96
34	Providence	1104	11	South St. Sub	South St 4kV	7.50	10.00	3.10	3.21	3.10	4.45	4.77	4.73	4.72	4.72	4.74	4.75	4.77	4.79	4.81	4.86	4.91
35	Providence	1110	11	Admiral Street	Rochambeau Ave Sub	7.50	10.00	4.93	3.20	5.70	4.43	4.75	4.71	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
36	Providence	1114	11	South St. Sub	Harris Ave sub	7.50	10.00	3.60	3.42	4.04	3.22	3.20	3.19	3.19	3.20	3.22	3.23	3.24	3.26	3.29	3.32	3.32
37	Providence	1120	11	Franklin Square sub	Harris Ave sub	7.50	10.00	3.22	2.50	3.00	4.12	4.42	4.38	4.37	4.37	4.39	4.41	4.42	4.44	4.46	4.50	4.55
38	Providence	1130	11	Franklin Square sub	Olneyville sub / Harris Ave	7.50	10.00	4.79	5.70	4.80	3.03	3.24	3.22	3.21	3.21	3.22	3.23	3.25	3.26	3.27	3.31	3.34
39	Providence	1132	11	Franklin Square sub	Olneyville sub	7.50	10.00	3.23	2.70	1.90	1.92	1.91	1.91	1.90	1.90	1.91	1.92	1.93	1.94	1.96	1.98	1.98
40	Providence	1134	11	South St. Sub	Olneyville sub	7.50	10.00	3.50	3.42	1.75	1.47	1.58	1.57	1.56	1.56	1.57	1.57	1.58	1.59	1.61	1.62	1.62
41	Providence	22	23	Admiral Street	Geneva	23.03	30.87	11.95	11.20	12.70	11.15	11.95	11.86	11.83	11.82	11.87	11.92	11.97	12.01	12.06	12.18	12.30
42	Providence	2201	23	South St. Sub	Sprague St. sub	20.00	25.00	3.30	3.88	3.70	3.06	3.28	3.25	3.25	3.24	3.26	3.27	3.28	3.30	3.31	3.34	3.38
43	Providence	2203	23	Elmwood sub	Sprague St. sub	20.00	25.00	4.12	4.20	4.00	3.78	4.05	4.02	4.01	4.01	4.02	4.04	4.05	4.07	4.09	4.13	4.17
44	Providence	2207	23	Franklin Square	Harris Ave	20.00	25.00	1.47	1.54	1.90	1.97	2.11	2.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
45	Providence	2210	23	Franklin Square	Elmwood Substation	20.00	25.00	4.20	4.20	10.90	2.85	3.06	3.04	3.03	3.03	3.04	3.05	3.06	3.07	3.09	3.12	3.15
46	Providence	2213	23	Elmwood Substation	Industrial Customers	32.67	32.67	1.63	4.20	5.20	1.33	1.42	1.41	1.41	1.41	1.42	1.42	1.43	1.44	1.45	1.46	1.46
47	Providence	2216	23	South St. Sub	Elmwood Substation	20.00	25.00	6.28	7.71	7.71	4.53	4.85	4.81	4.80	4.80	4.82	4.84	4.85	4.87	4.89	4.94	4.99
48	Providence	2220	23	Franklin Square	Elmwood Substation	20.00	25.00	6.47	6.47	6.47	5.21	5.58	5.54	5.53	5.53	5.55	5.57	5.59	5.61	5.64	5.69	5.75
49	Providence	2228	23	Elmwood Substation	Industrial Customers	14.54	14.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Providence	2235	23	Sockanosset Sub	Elmwood 12kV	35.93	38.64	24.63	24.63	22.60	24.14	25.85	25.66	25.61	25.58	25.68	25.79	25.89	25.99	26.10	26.36	26.62
51	Providence	2237	23	Admiral Street	Lippitt Hill Sub	20.00	25.00	7.10	6.85	6.87	7.07	7.48	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40
52	Providence	2239	23	Admiral Street	Lippitt Hill Sub	20.00	25.00	10.80	10.86	10.15	10.99	11.23	6.40	11.25	11.23	11.28	11.32	11.37	11.41	11.46	11.57	11.69
53	Providence	2248	23	South St. Sub	Rochambeau Ave / East George	20.00	25.00	8.50	8.03	7.20	7.72	8.27	8.21	8.19	8.18	8.21	8.25	8.28	8.31	8.35	8.43	8.51
54	Providence	2252	23	Admiral Street	Harris Ave	20.00	25.00	4.95	5.12	4.60	4.66	4.99	4.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	Providence	24	23	South St. Sub	East George	20.00	25.00	4.70	4.40	4.00	3.92	4.20	4.17	4.								

CLF 2-7
Seasonal Heat Pump Rate Design

Request:

Please provide a representative, archetype only, sub-transmission-level hourly load data (8760 profile).

Response:

After consultation with the Company, CLF has withdrawn this request, in part, due to the security risk posed by analyzing detailed data with artificial intelligence tools.

CLF 2-8
Seasonal Heat Pump Rate Design

Request:

Please provide a machine-readable capacity plan listing capacity-related projects, including: project ID/name, component type (feeder/substation/sub-transmission), expected kW or MVA capacity increase, and total project cost. If a table is not feasible, please provide a representative \$/kW capacity upgrade cost by component (feeder/substation/sub-transmission) and area type (urban/rural/coastal).

Response:

Representative \$/kW capacity upgrade cost by component (feeder/substation/sub-transmission) are provided below. There is no differentiation by area type (urban/rural/coastal).

Line No.	Equipment (a)	Unit Cost (b)	Measure (c)	MW (d)	\$/kW (e)
1	Power Transformer	\$3,000,000	Per Unit	55	\$54.5
2	Medium Voltage Substation	\$10,000,000	Per Unit	50	\$200.0
3	Feeder Position	\$2,000,000	Per Unit	12	\$166.7
4	Feeders Underground Line	\$6,000,000	Per Mile	10-12	\$500.0
5	Feeders Overhead Line	\$1,500,000	Per Mile	10-12	\$125.0
6	Service Transformer	\$8,000	Per Unit	.025-.05	\$160.0
7	Secondary	\$5	Per Foot	.025	\$0.2

Unit costs are provided in the table above and should be used circumspectly. Actual costs to solve system constraints can vary significantly. For instance, underground or overhead line extensions range from thousands of feet to many miles. Similarly, feeder positions and substation expansions are not always necessary. Alternately, the \$/kW-year costs contained in Attachment CLF 2-13 may be used.

CLF 2-9
Seasonal Heat Pump Rate Design

Request:

Please provide documentation of loss factors on secondary (customer to distribution transformer), primary feeder (transformer to substation), substation transformation, and sub-transmission.

Response:

Please see the Company's response to Amtrak 1-13, Attachment Amtrak 1-13-1, for primary and secondary loss factors. The Company does not maintain line-loss detail for the subcomponents of the voltage levels requested.

CLF 2-10
Seasonal Heat Pump Rate Design

Request:

Please provide the annual review feeder table that identifies “imminent thermal capacity constraints” as described in the FY 2027 Infrastructure, Safety and Reliability docket. Please note if this information is already contained in the feeder table requested in CLF 2-2.

Response:

Please refer to the Company's response to CLF 2-2.

CLF 2-11
Seasonal Heat Pump Rate Design

Request:

Please provide average transformer and secondary upgrade cost summary.

Response:

The average transformer and secondary upgrade cost summary is provided in the Company's response to CLF 2-8. A distance of 150 feet can be used for the secondary distance.

CLF 2-12
Seasonal Heat Pump Rate Design

Request:

Please provide current carrying charges or annualization factors that are used to convert \$/kW into \$/kW-year by component type, if the Company utilizes different carrying charges by component type.

Response:

\$/kW values are not converted into \$/kW-year values. The calculation for \$/kW-year values is included in Attachment CLF 2-13.

CLF 2-13
Seasonal Heat Pump Rate Design

Request:

Please provide latest, unredacted ICF Energy Efficiency Valuation Workbook or Extract, aka "ICF Trail," used by the Company in relevant energy efficiency planning and or dockets. For clarity, this workbook is referenced on page 291 of the AESC 2024 report.

Response:

Attachment CLF 2-13 includes the latest, unredacted ICF Energy Efficiency Valuation Workbook or Extract, aka "ICF Trail," used by the Company in relevant energy efficiency planning and or dockets.

Lookups

Line No.	Item (a)	Value (b)	Source (c)
1	Base Year	2025	User
2	Number of Historical Years	5	User
3	Number of Forecast Years	6	User
4	Historical Period	2020-2024	
5	Forecast Period	2025-2030	
6	Historical Escalation Rate	4.6%	Source: Federal Reserve Economic Data Implicit Price Deflator (Q1 2020 - Q1 2024)
7	Forecast Escalation Rate	2.2%	Source: Federal Reserve Economic Data Implicit Price Deflator (Q1 2024 - Q4 2024)
8	Distribution Percentage Assumed to be Related to Increasing Load	4.6%	From analysis of FY 2025 Electric Infrastructure, Safety, and Reliability Plan.
9	Transmission Percentage Assumed to be Related to Increasing Load	5.8%	From analysis of FY 2025 Electric Infrastructure, Safety, and Reliability Plan.
10	General Inflation	2.2%	BCR model
11	Non-PTF Percentage of Transmission Capital Investment	33.3%	Assumption
12	Percent of NEP Transmission Capital Investment Located in Rhode Island BEFORE Sale of NECO to PPL	25.0%	Assumption
13	Percent of NEP Transmission Capital Investment Located in Rhode Island AFTER Sale of NECO to PPL	0.0%	

Summary

Line No.	(a)	(b)	(c)	(d)
Transmission				
	Item	Units	Value	Source
1	Incremental Investments in Transmission Systems Caused by Load Growth	US\$	\$17,419,328	Trans Invmnt
2	Annual Carrying Charge of Transmission Capital Investments	%/yr	12.7%	Trans Carrying Charge
3	Transmission Incremental Growth in Peak Demand	MW	58	Peak Growth
4	Marginal Cost of Non-PTF Transmission Capacity	\$/kW-yr	\$38.18	
Distribution				
	Item	Units	Value	Source
5	Incremental Investments in Distribution Systems Caused by Load Growth	US\$	\$43,910,416	Dist Invmnt
6	Annual Carrying Charge of Distribution Capital Investments	%/yr	11.9%	Dist Carrying Charge
7	Distribution Incremental Growth in Peak Demand	MW	58	Peak Growth
8	Marginal Cost of Distribution Capacity	\$/kW-yr	\$90.05	

Transmission Investment

Line No.	Period (a)	Year (b)	Item (c)	Units (d)	Nominal Non-PTF NEP and NECO Value (e)	Real Non-PTF NEP and NECO Adjusted Value (f)
1			Historical Incremental Investments into Transmission Systems	US\$	\$167,045,950	\$146,205,591
2			Forecast Incremental Investments into Transmission Systems	US\$	\$147,841,553	\$153,997,311
3			Total Incremental Investments into Transmission Systems	US\$	\$314,887,504	\$300,202,902
4			Historical Incremental Investments Caused by Load Growth	US\$		\$8,483,606.24
5			Forecast Incremental Investments Caused by Load Growth	US\$		\$8,935,722.22
6			Total Incremental Investments Caused by Load Growth	US\$		\$17,419,328

Distribution Investment

Line No.	Period (a)	Year (b)	Item (c)	Units (d)	NECO Nominal Value (e)	NECO Real Value (f)
1			Historical Incremental Investments into Distribution Systems	US\$	\$509,684,826	\$585,617,834
2			Forecast Incremental Investments into Distribution Systems	US\$	\$378,520,340	\$365,692,428
3			Total Incremental Investments into Distribution Systems	US\$	\$888,205,166	\$951,310,262
4			Historical Incremental Investments Caused by Load Growth	US\$		\$27,030,848
5			Forecast Incremental Investments Caused by Load Growth	US\$		\$16,879,569
6			Total Incremental Investments Caused by Load Growth	US\$		\$43,910,416

Transmission Carrying Charge

Line No.	Item (a)	Units (b)	NECO Value (c)	NECO Source (d)
	After Tax Cost of Financing (WACC)	%	5.9%	
1	Share of project financed through debt	%	50.0%	Assumption
2	Real Interest Rate on Debt	%	2.8%	
3	Nominal Interest Rate on Debt	%	5.1%	Assumption
4	Expected After Tax Real Return on Equity	%	9.5%	
5	Expected After Tax Nominal Return on Equity	%	12.0%	Assumption
6	State Income Tax Rate	%	0.0%	Adael Acosta, Director, U.S. Indirect and Employment Tax, 8/30/21 (National Grid)
7	Federal Income Tax Rate	%	21.0%	FERC Form 1, page 51 of 216
8	Effective State and Federal Income Tax Rate	%	21.0%	
	Property Taxes Expense	%	1.5%	
9	Total Plant Annual Property (Real Estate) Taxes	MM\$	\$48.4	FERC Form 1, pages 320-323, line 164, column b
10	Net Book Value of Total Plant	MM\$	\$3,285.7	
	Insurance Expense	%	0.1%	
11	Total Plant Annual Insurance Costs	MM\$	\$2.3	FERC Form 1, pages 320-323, line 185, column b
12	Net Book Value of Total Plant	MM\$	\$3,285.7	FERC Form 1, pages 200-201, line 15, column c
	Depreciation Expense (using Sinking Fund Factor Approach)	%	1.6%	
13	Depreciation Life of Transmission Plant	Yr	27	Assumption
	Operation and Maintenance Expense	%	2.7%	
14	Annual Transmission Operation and Maintenance Expenses	MM\$	\$48.1	
15	Net Book Value of Transmission Plant	MM\$	\$1,787.0	
16	Electric Plant in Service	MM\$	\$2,080.3	FERC Form 1, pages 204-207, line 58, column g
17	Accumulated Depreciation	MM\$	\$293.2	FERC Form 1, page 219, line 25, column b
	Income Taxes Expense	%	1.0%	
18	Gross up factor for taxes	%	79.0%	
19	Annual Real Carrying Charge of Capital Investments	%	12.7%	

Distribution Carrying Charge

Line No.	Item (a)	Units (b)	NECO Value (c)	NECO Source (d)
	After Tax Cost of Financing (WACC)	%	5.9%	
1	Share of project financed through debt	%	50.0%	Assumption
2	Real Interest Rate on Debt	%	2.8%	
3	Nominal Interest Rate on Debt	%	5.1%	Assumption
4	Expected After Tax Real Return on Equity	%	9.5%	
5	Expected After Tax Nominal Return on Equity	%	12.0%	Assumption
6	State Income Tax Rate	%	0.0%	Adael Acosta, Director, U.S. Indirect and Employment Tax, 8/30/21 (National Grid)
7	Federal Income Tax Rate	%	21.0%	FERC Form 1, page 109 of 213
8	Effective State and Federal Income Tax Rate	%	21.0%	
	Property Taxes Expense	%	1.5%	
9	Total Plant Annual Property (Real Estate) Taxes	MM\$	\$48.4	FERC Form 1, pages 320-323, line 164, column b
10	Net Book Value of Total Plant	MM\$	\$3,285.7	
	Insurance Expense	%	0.1%	
11	Total Plant Annual Insurance Costs	MM\$	\$2.3	FERC Form 1, pages 320-323, line 185, column b
12	Net Book Value of Total Plant	MM\$	\$3,285.7	FERC Form 1, pages 200-201, line 15, column c
	Depreciation Expense (using Sinking Fund Factor Approach)	%	1.6%	
13	Depreciation Life of Distribution Plant	Yr	27	Assumption
	Operation and Maintenance Expense	%	1.9%	
14	Annual Distribution Operation and Maintenance Expenses	MM\$	\$23.4	
15	Net Book Value of Distribution Plant	MM\$	\$1,246.4	
16	Electric Plant in Service	\$	\$2,080.3	FERC Form 1, pages 204-207, line 75, column g
17	Accumulated Depreciation	\$	\$833.9	FERC Form 1, page 219, line 26, column b
	Income Taxes Expense	%	1.0%	
18	Gross up factor for taxes	%	79.0%	
19	Annual Real Carrying Charge of Capital Investments	%	11.9%	

Peak Growth

Line No.	Period (a)	Year (b)	Item (c)	Units (d)	NECO Value (e)	NECO Source (f)
1			Total incremental growth in peak demand	MW	58	

Appendix: Transmission and Distribution Operation and Maintenance Cost Avoidable Expenses

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
Operation Transmission Expenses						
	Item	Total NECO Value	NECO Source	Share Avoidable	Source	Avoidable NECO Value
1	(560) Operation Supervision and Engineering	\$524,899	FERC Form 1, pages 320-323, line 83, column b		0% Assumption	\$0
2	(561) Load Dispatching	\$10,099,438	FERC Form 1, pages 320-323, lines 85-92, column b		0% Assumption	\$0
3	(562) Station Expenses	\$416,070	FERC Form 1, pages 320-323, line 93, column b		10% Assumption	\$41,607
4	(563) Overhead Lines Expenses	\$290,191	FERC Form 1, pages 320-323, line 94, column b		20% Assumption	\$58,038
5	(564) Underground Lines Expenses	\$0	FERC Form 1, pages 320-323, line 95, column b		20% Assumption	\$0
6	(565) Transmission of Electricity by Others	\$225,756,476	FERC Form 1, pages 320-323, line 96, column b		20% Assumption	\$45,151,295
7	(566) Miscellaneous Transmission Expenses	\$3,099,930	FERC Form 1, pages 320-323, line 97, column b		50% Assumption	\$1,549,965
8	(567) Rents	\$119,514	FERC Form 1, pages 320-323, line 98, column b		0% Assumption	\$0
9	Total	\$240,306,518				\$46,800,905
Maintenance Transmission Expenses						
	Item	Total NECO Value	NECO Source	Share Avoidable	Source	Avoidable NECO Value
10	(568) Maintenance Supervision and Engineering	\$196,019	FERC Form 1, pages 320-323, line 101, column b		0% Assumption	\$0
11	(569) Maintenance of Structures	\$585	FERC Form 1, pages 320-323, lines 102-106, column b		20% Assumption	\$117
12	(570) Maintenance of Station Equipment	\$669,100	FERC Form 1, pages 320-323, line 107, column b		20% Assumption	\$133,820
13	(571) Maintenance of Overhead Lines	\$4,082,823	FERC Form 1, pages 320-323, line 108, column b		20% Assumption	\$816,665
14	(572) Maintenance of Underground Lines	-\$45	FERC Form 1, pages 320-323, line 109, column b		20% Assumption	-\$9
15	(573) Maintenance of Miscellaneous Transmission Plant	\$740,920	FERC Form 1, pages 320-323, line 110, column b		50% Assumption	\$370,460
16	Total	\$5,689,402				\$1,320,953
Total Transmission Expenses				976		
	Item	Total NECO Value	NECO Source	Share Avoidable	Source	Avoidable NECO Value
17	Total Operation and Maintenance Transmission Expense	\$245,995,920				\$48,121,858
Operation Distribution Expenses						
	Item	Total NECO Value	NECO Source	Share Avoidable	Source	Avoidable NECO Value
18	(580) Operation Supervision and Engineering	\$5,143,879	FERC Form 1, pages 320-323, line 134, column b		0% Assumption	\$0
19	(581) Load Dispatching	\$11,103,570	FERC Form 1, pages 320-323, line 135, column b		0% Assumption	\$0
20	(582) Station Expenses	\$1,341,239	FERC Form 1, pages 320-323, line 136, column b		10% Assumption	\$134,124
21	(583) Overhead Line Expenses	-\$2,093,872	FERC Form 1, pages 320-323, line 137, column b		20% Assumption	-\$418,774
22	(584) Underground Line Expenses	\$1,498,657	FERC Form 1, pages 320-323, line 138, column b		20% Assumption	\$299,731
23	(585) Street Lighting and Signal	\$14,170	FERC Form 1, pages 320-323, line 139, column b		0% Assumption	\$0
24	(586) Meter Expenses	\$5,342,587	FERC Form 1, pages 320-323, line 140, column b		0% Assumption	\$0
25	(587) Customer Installations Expenses	\$249,404	FERC Form 1, pages 320-323, line 141, column b		0% Assumption	\$0
26	(588) Miscellaneous Expenses	\$11,016,897	FERC Form 1, pages 320-323, line 142, column b		50% Assumption	\$5,508,449
27	(589) Rents	\$194,930	FERC Form 1, pages 320-323, line 143, column b		0% Assumption	\$0
28	Total	\$33,811,461				\$5,523,529
Maintenance Distribution Expenses						
	Item	Total NECO Value	NECO Source	Share Avoidable	Source	Avoidable NECO Value
29	(590) Maintenance Supervision and Engineering	-\$1,289,739	FERC Form 1, pages 320-323, line 146, column b		0% Assumption	\$0
30	(591) Maintenance of Structures	\$98,509	FERC Form 1, pages 320-323, line 147, column b		20% Assumption	\$19,702
31	(592) Maintenance of Station Equipment	\$686,101	FERC Form 1, pages 320-323, line 148, column b		10% Assumption	\$68,610
32	(593) Maintenance of Overhead Lines	\$87,948,402	FERC Form 1, pages 320-323, line 149, column b		20% Assumption	\$17,589,680
33	(594) Maintenance of Underground Lines	\$626,726	FERC Form 1, pages 320-323, line 150, column b		20% Assumption	\$125,345
34	(595) Maintenance of Line Transformers	\$87,287	FERC Form 1, pages 320-323, line 151, column b		20% Assumption	\$17,457
35	(596) Maintenance of Street Lighting and Signal	\$357,898	FERC Form 1, pages 320-323, line 152, column b		0% Assumption	\$0
36	(597) Maintenance of Meters	\$23,898	FERC Form 1, pages 320-323, line 153, column b		0% Assumption	\$0
37	(598) Maintenance of Miscellaneous Distribution Plant	\$68,040	FERC Form 1, pages 320-323, line 154, column b		50% Assumption	\$34,020
38	Total	\$88,606,922				\$17,854,815
Total Distribution Expenses						
	Item	Total NECO Value	NECO Source	Share Avoidable	Source	Avoidable NECO Value
40	Total Operation and Maintenance Distribution Expense	\$122,418,383				\$23,378,344

**STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION**

IN RE: THE NARRAGANSETT ELECTRIC COMPANY :
d/b/a RHODE ISLAND ENERGY APPLICATION FOR : **DOCKET NO. 25-45-GE**
APPROVAL OF A CHANGE IN ELECTRIC AND GAS :
BASE DISTRIBUTION RATES :

**CONSERVATION LAW FOUNDATION’S FOURTH SET OF DATA
REQUESTS DIRECTED TO RHODE ISLAND ENERGY
(Issued: March 31, 2026)**

Heat pump rates

- CLF 4-1. Does the Company compile full-year hourly load profiles (8760s) for feeders and transformers?
- (a) If not, explain why not.
 - (b) Please provide raw SCADA data if available. If not, explain why not.
- CLF 4-2. Please explain whether the Company tracks the hours at which the historical peaks of each feeder and transformer occur. If so, please provide a spreadsheet that includes the hourly intervals.
- (a) If not, please explain why not.
 - (b) If not, please explain whether it is relevant to the annual screening process to know when precisely the peak occurs.
- CLF 4-3. Please explain whether the Company compiles and tracks the historical winter peaks and/or forecasts future peaks and the feeder and transformer levels. If not, explain why not.
- (a) Please explain whether historical and/or forecasted future winter peaks are relevant to the annual screening process.
 - (b) Please explain whether, to the best of the Company’s knowledge, any feeders or transformers are currently constrained or forecasted to have future constraints in the winter.
 - (c) Please explain the distribution planning team’s best assessment of when winter peak growth will start to constrain feeders and/or transformers, and thereby start creating distribution costs.

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

APPLICATION FOR APPROVAL
OF A CHANGE IN ELECTRIC AND
GAS BASE DISTRIBUTION RATES

Rhode Island Energy's Responses to
the Fourth Set of Data Requests from
Conservation Law Foundation

Book 1 of 1

April 22, 2026

Submitted to:
Rhode Island Public Utilities Commission
Docket No. 25-45-GE

Submitted by:



Rhode Island Energy™
a PPL company

CLF 4-1
Heat Pump Rates

Request:

Does the Company compile full-year hourly load profiles (8760s) for feeders and transformers?

- (a) If not, explain why not.
- (b) Please provide raw SCADA data if available. If not, explain why not.

Response:

The Company does not compile 8760 profiles for feeders and transformers on a regular basis.

- (a) The system is planned around summer peak day loading. This is done because the system is summer-peak limited, and Rhode Island Energy does not currently have technologies installed that can manage or actively reduce the summer peak. Therefore, creation of labor-intensive 8760 profiles is unnecessary.
- (b) The Company does not provide raw SCADA data externally. The data is incomplete, and the raw data requires careful analysis and vetting to remove anomalies and data errors that occur from communication errors, switching events, or other issues.

CLF 4-2
Heat Pump Rates

Request:

Please explain whether the Company tracks the hours at which the historical peaks of each feeder and transformer occur. If so, please provide a spreadsheet that includes the hourly intervals.

- (a) If not, please explain why not.
- (b) If not, please explain whether it is relevant to the annual screening process to know when precisely the peak occurs.

Response:

- (a) The hour at which the peak occurs is not tracked as it is not necessary for current distribution planning practices focused on peak level analysis, which involves analyzing the magnitude of the peak value and its impact on thermal and voltage limits, not the hour when it occurred. The Company may move to 8760 analyses in the future; however, there are data processing and sensing improvements required in the tools currently used and the system equipment as described within Rhode Island Energy's Grid Modernization Plan.
- (b) The precise time of the peak is not relevant to the specific device being studied. For instance, a feeder can be studied using its peak value without the peak time. Similarly, a transformer can be studied using its peak value without its peak time. In the transformer case, it is true that the underlying feeders add at a precise time to create the transformer peak, but the transformer peak is used for analysis and not the sum of the feeder peaks. Currently, the Rhode Island system is a summer-peaking area, with peak loading typically occurring roughly the same time and hour each summer.

CLF 4-3
Heat Pump Rates

Request:

Please explain whether the Company compiles and tracks the historical winter peaks and/or forecasts future peaks and the feeder and transformer levels. If not, explain why not.

- (a) Please explain whether historical and/or forecasted future winter peaks are relevant to the annual screening process.
- (b) Please explain whether, to the best of the Company's knowledge, any feeders or transformers are currently constrained or forecasted to have future constraints in the winter.
- (c) Please explain the distribution planning team's best assessment of when winter peak growth will start to constrain feeders and/or transformers, and thereby start creating distribution costs.

Response:

The Company does not compile or track historical winter peaks nor forecast winter peaks at the feeder or transformer level. The Rhode Island distribution system is currently summer-limited. The Company concentrates on summer analysis for efficiency reasons: if the system is summer-limited and it is planned sufficiently, then the system will be sufficient in the winter.

- (a) The Rhode Island distribution system is currently summer-limited. Therefore, historical and/or forecasted future winter peaks are not relevant to the annual screening process at this time.
- (b) There are no feeders or transformers that are currently winter-constrained. Considering the current assumptions regarding customer adoption of heat pumps and the current system-level winter forecast, the system winter peak is not expected to exceed the summer peak forecast through 2039. This does not imply that there may not be localized winter constraints prior to 2039.
- (c) The Company's latest assessment of winter peak growth was done within its Grid Modernization Plan. The Company estimates that the system and underlying components will not become winter-limited until the mid to late 2030s.

CLF 4-4
Time-of-Use Rates

Request:

Please refer to Witness Fang's testimony page 60 lines 8 through 18. The testimony states that the Clarum Advisors and GridX team "gather customer interval data from the Company's deployment of AMF meters, utility system data, energy cost data, customer billing and segmentation data, and other relevant data streams to upload to Analyze. Leveraging analysis from the Analyze platform, the team will develop a set of potential rate design options. Components of these rate design options will include peak period window definitions, seasonality, prices and price premiums by period, opt-in versus opt-out design, and other key characteristics."

- (a) How many months of customer interval data will the team collect before designing rate options? Please explain why the Company believes that amount of customer interval data will be necessary to begin designing rate options.
- (b) After designing initial rate options, how does the Company plan to continue to incorporate customer interval data to update TVR designs?
- (c) Has the Company begun any initial planning discussions with the Clarum Advisors and GridX team around opt-in versus opt-out design? If so, please describe any initial plans.

Response:

- (a) The Company intends to use twelve months of customer interval data (i.e., AMF data) to inform development of initial time-varying rate ("TVR") options. Twelve months of interval data is generally preferred because it captures seasonal variation in customer usage and system conditions and supports a rigorous, customer-centric rate design that anticipates structural beneficiaries and non-beneficiaries, manages bill impacts, and establishes meaningful price incentives (please see the Pre-Filed Direct Testimony of Cynthia Fang, Book 5, Bates page 23, lines 3-13; Bates page 66, line 14 through Bates page 67, line 12). When twelve months of interval data is not available for the entire population, best practice includes validating that customers with a full year of interval data are representative of the Company's broader population, modeling adjustments, and extrapolating from partial-year to full-year interval data (see Book 5, Bates page 25, lines 9-13).

The Company will monitor customer interval data in order to determine customer response (e.g., observed load shifting) to TVR rates and to inform whether refinements to the rates are warranted. The specifics—including what metrics will be monitored and the cadence for evaluating and/or updating TVR designs—will be determined during the TVR rate design process and documented in the Company's TVR Implementation Plan

CLF 4-4, page 2

(see Book 5, Bates page 64, line 20 through Bates page 65, line 3; Bates page 66, lines 1-18). In establishing any updated cadence, the Company will balance the benefits of incorporating learnings from interval data against the potential downside of overly frequent changes that could create customer confusion or discourage participation.

- (b) The Company has not yet begun detailed planning discussions with Clarum Advisors and GridX regarding whether any future TVR offering will be designed as opt-in or opt-out. As described in the testimony, opt-in versus opt-out is a key design characteristic that will be evaluated during the TVR design phase (see Book 5, Bates page 58, lines 1-3; Bates page 60, line 20 through Bates page 61, line 14). The Company expects to consider the benefits and tradeoffs of each approach as part of the broader, data-driven rate design process and stakeholder engagement activities.

CLF 4-5
Time-of-Use Rates

Request:

Please refer to Witness Fang's testimony page 64 lines 10 through 12. Please explain why the Company's goal to begin developing rate options in early 2027 could potentially be delayed.

Response:

The Pre-Filed Direct Testimony of Cynthia Fang does not suggest that any aspect of the TVR development timeline is likely to be delayed; rather Ms. Fang explains that the Company's intention to begin developing TVR rate options in early 2027 is based on two key prerequisites: (1) implementing GridX's Analyze tool, which may take approximately six months, and (2) having sufficient AMF interval data available that is representative of the customer population and key subgroups. As explained, because AMF deployment is proceeding geographically, customers with a full year of AMF data available prior to early 2027 may not be representative of the overall population and certain subgroups, which could require additional time and statistical work to support appropriate representativeness (see Book 5, Bates page 66, line 14 through Bates page 67, line 12). In addition, Ms. Fang notes that implementation of the Analyze tool may take six months and that the Company is likely to have sufficient interval data available in early 2027; these factors together align with the Company's intention to begin developing rate options, leveraging the GridX solution and customer interval data, in early 2027 (Book 5, Bates page 67, lines 7-12). The Company's proposed workplan between the Company, GridX, and Clarum provides for some leeway in completing these two prerequisites without impacting the overall schedule.

CLF 4-6
Time-of-Use Rates

Request:

Please refer to Witness Fang's testimony at page 38. Does the company intend to offer a comprehensive online rate comparison tool like PSEG LI?

Response:

In my role as consultant advising and assisting the Company in its development of proposed TOU/TVR designs, I have been authorized to represent the Company's positions on its future plans and intentions regarding the development of those designs.

The Company has not yet begun detailed planning discussions. Detailed aspects of TVR design and deployment will be decided during the TVR development process.

CLF 4-7
Time-of-Use Rates

Request:

What outreach and engagement around time-varying rates has the company conducted with its large commercial and industrial customers to date?

Response:

The Company has not conducted any outreach and engagement around time-varying rates with any customers to date. Please see the Pre-Filed Direct Testimony of Cynthia Fang for a description of the timing of the Company's outreach and engagement as part of the TVR development process.

CLF 4-8
Time-of-Use Rates

Request:

When analyzing the impacts of each rate design option on target populations and key customer segments, what populations and customer segments will the Company evaluate?

Response:

As described in the Pre-Filed Direct Testimony of Cynthia Fang, the Company will evaluate impacts of each rate design option both by rate class and for key customer subgroups, using representative samples of customers with advanced metering functionality data and apply appropriate statistical techniques to validate representativeness of the samples for the target populations (see Book 5, Bates page 61, lines 1-14). The Company expects to analyze impacts on the target population and key customer segments, such as households with low income and EV owners, and may also consider additional subgroups informed by the data and stakeholder engagement, including structural beneficiaries and structural non-beneficiaries and other vulnerable customer populations (see Book 5, Bates page 61, lines 7-9; Bates page 25, lines 7-9; Bates page 28, lines 8-15).

CLF 4-9
Time-of-Use Rates

Request:

Does the Company plan to propose shadow billing ahead of the implementation of any TOU rates?

- (a) If not sure of plans, please explain when the Company would decide on shadow billing implementation.
- (b) If so, please explain how long the shadow billing is planned to last.

Response:

Please see the Company's response to CLF 4-6 as shadow billing is one of the detailed aspects of TVR design and deployment addressed in the Company's response.

CLF 4-10
Time-of-Use Rates

Request:

Does the Company plan to consider a bill stabilization program for low-income customers, or any other measure to protect low-income customers from bill spikes in at least the first year of the program?

Response:

Please see the Company's response to CLF 4-6 as bill stabilization for low-income customers is one of the detailed aspects of TVR design and deployment addressed in the Company's response.

CLF 4-11
Time-of-Use Rates

Request:

Has the Company considered using advanced metering infrastructure data to monitor customer load profile changes to identify risks and intervention opportunities (e.g., to monitor energy-limiting behavior to inform targeted protections; to identify non-shiftable loads, e.g., medical devices; to target incentives or affordable access to enabling technology to low-income households that could benefit)?

Response:

- (a) The Company has and is contemplating the use of advanced metering infrastructure data to monitor customer load profiles. The Company's primary use of the data will be to refine its distribution planning procedures to potentially identify new load-to-generation balancing or load shifting alternatives to address system needs. The Company acknowledges that advanced metering data could be used, but was not intending, to analyze behaviors or changes of individual customers.
- (b) As noted in the Pre-Filed Direct Testimony of Cynthia Fang, one of the measures of a successful TVR implementation is the ability to deliver load-shifting behavior and/or peak-load reduction. Advanced metering infrastructure data plays a critical role in the Company's ability to monitor changes in customer load profiles resulting from TVR. After TVR implementation, the Company will use advanced metering infrastructure data to examine how customers, at the full population level, and specific groups of customers, shift load in response to TVR.

CLF 4-13
Time-of-Use Rates

Request:

What are the Company's plans to coordinate with municipal aggregations that are interested in offering TVR for supply?

Response:

Please see the Company's response to CLF 4-6 as coordinating with municipal aggregations is one of the detailed aspects of TVR design and deployment addressed in the Company's response.

CLF 4-14
Time-of-Use Rates

Request:

Does the Company plan to consider geographic targeting of marketing, education, and outreach efforts, and sequence the transition of customers to TOU rates based on geography?

Response:

The Company expects to consider targeted marketing, education, and outreach (“ME&O”) approaches and phased or batched enrollment as part of TVR implementation planning. As described in the Pre-Filed Direct Testimony of Cynthia Fang, best practice enrollment and delivery planning includes determining whether to enroll customers at a single point in time or to undertake enrollment gradually in waves or batches, and using data-driven analysis to determine an appropriate sequence (see Book 5, Bates page 63, lines 6-22).

Although geography may be one consideration in tailoring ME&O and sequencing enrollment—particularly where geographic patterns correlate with customer characteristics and needs—Ms. Fang’s testimony identifies sequencing based on expected bill impacts (e.g., enrolling structural beneficiaries and customers most likely to experience bill savings first) as a best-practice approach to support gradualism, generate positive word-of-mouth, and facilitate smoother enrollment of later cohorts (see Book 5, Bates page 23, lines 3-13; Bates page 63, lines 6-22).

Similarly, the Company expects ME&O to be tailored to key customer subgroups that may warrant different messaging and education approaches, such as structural non-benefiters and customers forecast to experience bill increases under TVR (see Book 5, Bates page 64, lines 1-18).

Consistent with these principles, the Company will evaluate whether, and how, geographic targeting should be incorporated alongside customer subgroup targeting during development of the Enrollment and Delivery Plan and the comprehensive ME&O Plan, which will be documented in the Company’s TVR Implementation Plan (see Book 5, Bates page 63, lines 6-22; Bates page 64, lines 1-18).

CLF 4-15
Time-of-Use Rates

Request:

What are the Company's plans for involving stakeholders (e.g., ratepayers, low-income advocates, community groups, ME&O professionals, aggregators) in the development and implementation of a ME&O plan?

Response:

Stakeholder engagement is one of the three key success factors identified in the Pre-Filed Direct Testimony of Cynthia Fang as critical to successful TVR development and deployment (see Book 5, Bates page 27, line 20 through Bates page 28, line 3). As described, the Company proposes to leverage the Power Sector Transformation Advisory Group ("PSTAG") as the primary forum to engage stakeholders, report out on progress, and incorporate input throughout TVR design and implementation planning (see Book 5, Bates page 59, line 19 through Bates page 60, line 6). Ms. Fang's testimony further states that the Company intends to engage PSTAG at the outset of the TVR design phase and to keep the group engaged throughout all portions of TVR design and implementation planning, and that the Company will continue to solicit and consider feedback from PSTAG throughout TVR implementation plan development (see Book 5, Bates page 59, line 19 through Bates page 60, line 6; Bates page 62, line 18 through Bates page 63, line 4).

CLF 4-16
Time-of-Use Rates

Request:

In planning for MEO efforts associated to TOU rates,

- (a) How far in advance of TOU implementation would MEO efforts begin?
- (b) Can the Company begin developing and implementing a MEO plan before the Company's next rate case?
- (c) If not, what is needed before the Company can begin developing and implementing a MEO plan?
- (d) How will the Company ensure there is an adequate MEO period before TOU rate rollout begins?
- (e) How will the Company ensure that MEO planning and implementation does not delay implementation of TOU rates?

Response:

- (a) As described in the Pre-Filed Direct Testimony of Cynthia Fang, the Company expects to develop its comprehensive ME&O plan as part of its TVR Implementation Plan during 2027, subject to Commission approval in this proceeding of cost recovery for TVR implementation (see Book 5, Bates page 64, line 20 through Bates page 65, line 3). The specific start date and lead time for ME&O activities relative to TOU/TVR rollout will be established during TVR implementation planning based on the selected rate design, enrollment approach (e.g., waves/batches versus single point-in-time), and stakeholder input.
- (b) Yes. The Company can begin developing its ME&O plan before its next base distribution rate case, provided cost recovery for TVR implementation is approved in this proceeding.
- (c) See response to part (b), above.
- (d) The Company will ensure an adequate ME&O period before TOU/TVR rollout by establishing the timing, sequencing, and duration of ME&O activities within the TVR Implementation Plan developed in 2027. Consistent with Ms. Fang's testimony, stakeholder input through Power Sector Transformation Advisory Group ("PSTAG") will be incorporated throughout development of the implementation plan, including to inform an appropriate ME&O approach and timeline (see Book 5, Bates page 62, line 18 through Bates page 63, line 4; Bates page 64, line 20 through Bates page 65, line 3).

CLF 4-16, page 2

- (e) The Company will align ME&O planning with the overall implementation schedule as part of the TVR Implementation Plan so that customer education and enrollment activities support—rather than delay—TOU/TVR rollout. The Company also will use stakeholder engagement (including through PSTAG) to help ensure the ME&O plan is practicable and appropriately timed (see Book 5, Bates page 62, line 18 through Bates page 63, line 4; Bates page 64, line 20 through Bates page 65, line 3).

CLF 4-17
Time-of-Use Rates

Request:

Is the Company considering implementing TVR into rates in phases – e.g., time-varying the different rate components (supply, transmission, distribution) in sequence?

Response:

In my role as consultant advising and assisting the Company in its development of proposed TOU/TVR designs, I have been authorized to represent the Company's positions on its future plans and intentions regarding the development of those designs.

As described in the Pre-Filed Direct Testimony of Cynthia Fang, there are multiple potential approaches to the basis for time-varying prices, including supply-based approaches that reflect wholesale market prices/marginal energy costs and demand- or system load-based approaches that can reflect marginal costs associated with system load and cost of service (see Book 5, Bates page 49, lines 9-22). The Company expects to evaluate these approaches—including whether any phased implementation by component is appropriate—during the TVR rate design process and to document the selected approach in the TVR Implementation Plan.

CLF 4-18
Time-of-Use Rates

Request:

How will the Company incorporate flexibility into TOU rate designs, ensuring that rate designs can adapt to system conditions, especially as electrified loads, such as EVs and heat pumps, increase?

Response:

In my role as consultant advising and assisting the Company in its development of proposed TOU/TVR designs, I have been authorized to represent the Company's positions on its future plans and intentions regarding the development of those designs.

The Company will propose changes to its rates as normal course of business, such as in subsequent rate cases. Any such changes will consider ratemaking principles, like cost causation, and best practices.

CLF 4-19
Time-of-Use Rates

Request:

Does the Company plan on implementing a TVR pilot as a randomized controlled trial before developing a TVR Implementation Plan? If not, please explain why not.

Response:

The Company does not propose to implement a TVR pilot, whether as a randomized controlled trial or not. As noted in the Pre-Filed Direct Testimony of Cynthia Fang, there have been sufficient TVR pilots and program implementation across the nation, including by other utilities under the Company's former parent company, National Grid, and other utilities in the Northeast, to inform the development of best practices such that further delay of broader implementation of TVR for additional pilots is not warranted. The Company's TVR development proposal is designed with these best practices in mind. The Company's data driven approach, which includes functionality provided by GridX's software, allows for rigorous analysis of TVR impacts and will help the Company navigate lessons learned from other pilots. Given the limited incremental value of a TVR pilot, and given the associated delay and cost, there is not a compelling justification for offering a TVR pilot or randomized control trial.

CLF 4-20
Time-of-Use Rates

Request:

Please provide a simple list of dates that correlate with the steps listed in Section IV: TVR Implementation Planning Process in Witness Fang's testimony.

Response:

The below dates are approximate and reflect a sequential workplan assumed in Witness Fang's Section IV (TVR Implementation Planning Process), premised on Rhode Island Public Utilities Commission approval in this proceeding of cost recovery for TVR development.

- GridX Analyze tool implementation: September 2026 – February 2027
- Stakeholder engagement: beginning September 2026 (ongoing thereafter)
- Designing TVR options: February – April 2027
- Analysis of customer-level TVR option tradeoffs: April – June 2027
- Designing customer ME&O plan: June – August 2027
- Creating TVR Implementation Plan: July – September 2027