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

Grid Modernization Plan And Attachments

Schedule KC/RC/WR-1

Book 2 of 2

December 30, 2022

RIPUC Docket No. 22-56-EL

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Index

SECTION 8: BCA EVALUATION UNDER DOCKET NO. 4600

SECTION 9: CONCLUSION

ATTACHMENTS

Executive Summary

EXECUTIVE SUMMARY

The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") presents as its grid modernization plan ("GMP") this holistic suite of grid modernization[1] investments. The GMP builds on the previous proposals originally submitted in Docket Nos. 4770 and 4780 and addresses input received from stakeholders over the past four years. The GMP also reflects PPL Corporation's ("PPL") experience implementing grid modernization investments and solutions for PPL Electric Utilities Corporation ("PPL Electric") in its Pennsylvania service territory. As a result, the Company has developed a GMP that comprises a portfolio of integrated technologies to provide digital intelligence and automation to create a more efficient, resilient electric system capable of efficiently utilizing all grid-connected resources to properly address technical and operational issues arising from the rapidly changing operating characteristics of the power system and to cost-effectively meet customer expectations as the State moves into the energy future.

The GMP serves three purposes.

First, the GMP demonstrates the need to make certain "Foundational Investments."[2] The Foundational Investments, also referred to as "near term investments", described in the GMP encompass six years of proposed investments in a portfolio of software, communication and advanced field devices that work together and are enhanced with advanced metering functionality ("AMF").[3] These Foundational Investments are necessary to provide safe and reliable service today and in the future, as the electric distribution grid transforms with the proliferation of DER.[4] Customers have been adopting DER for more than a decade, and the Company forecasts that trend will continue and accelerate, driven by both customer preference and by the imperative to meet the State's Climate Mandates.[5] Interconnecting them

[1] The Company uses the term "grid modernization" to refer to those investments associated with managing the distribution system with more granularity to create a platform of solutions that transforms the grid enabling distributed energy resources ("DER") to interconnect to achieve Rhode Island's Climate Mandates (as defined herein) while also giving customers more control over their energy decisions, reducing energy use, and improving reliability. Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably.
[2] The Foundational Investments outlined in this GMP are distinct from and build upon the initial, limited suite of grid modernization investments that the PUC approved in the Company's last general rate case in Docket No. 4770 to start grid modernization. This distinction is further discussed in Section 2.3, *infra.*
[3] The AMF Business Case was filed with the Rhode Island Public Utilities Commission ("PUC") in November 2022 in Docket No. 22-49-EL to replace AMR technology which among other things, is reaching the end of its design life, is obsolete and will not scale.
[4] DER are resources sited close to customers that can provide electricity generation, including both distributed generation installations ("DG") and flexible demand (e.g., energy storage, EV, EHP).
[5] The 2021 Act on Climate set forth enforceable, statewide, economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45% below 1990 levels by 2030, 80% by 2040, and to achieve net-zero emissions by 2050. The 2022 amendments to the Renewable Energy Standard further accelerate the shift to renewable energy

into the existing electric system infrastructure is becoming increasingly difficult, expensive and operationally challenging. The Company's existing electric distribution system provides little distribution system operator visibility and limited automated control. It is necessary to accelerate grid transformation to manage system complexity that is caused by increased DER penetration and electrification that is already occurring and anticipated to grow significantly. Rhode Island needs a well-coordinated and integrated grid modernization plan to meet the resulting operational and customer needs. The Foundational Investments in this GMP are necessary to ensure safe and reliable system operations for any DER adoption scenario.

The Foundational Investments will unlock reliability management solutions, improved situational awareness and system control, reduced DG interconnection costs, improved DER operations and experience, greater customer insight into control over energy usage, and affordability options – all of which are explained in detail throughout this GMP. The capabilities provided by the Foundational Investments represent a new paradigm for grid operations with greatly enhanced situational awareness and control that further emphasizes the importance of reliability, resilience, and operational flexibility. For example, one of the capabilities enabled by these Foundational Investments is DER Monitor/Manage, which permits utility control of DER devices to adjust DER output to benefit the grid. This capability minimizes the need for DER curtailment and provides the wherewithal to balance load and generation for a stable, reliable system.[6]

Further, these Foundational Investments are critical to meeting the Climate Mandates. Enabling DER adoption, in particular renewable DG, electric vehicles ("EV"), and electric heat pump ("EHP") adoption will enable customers to reduce their overall carbon footprint, including reducing transportation-related emissions that make up 40% of the State's carbon dioxide ("CO2") emissions.[7] Without these investments, the Company will need to continue to make piecemeal investments in distribution system infrastructure rather than being able to optimize those investments to benefit all customers and meet specific identified needs. Consequently, DG adoption rates likely will slow, EV charging infrastructure likely will be more costly, and customer participation in DER and energy efficiency ("EE") programs likely will be less robust, likely putting the Climate Mandates out of reach. The Foundational Investments are critical to the operation of the electric grid regardless of the ultimate

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resources by requiring 100% of electricity used in the State be generated by renewable energy resources by 2033. In this GMP, the Company refers to these statutory requirements collectively as the "Climate Mandates."

[6] The Company is assessing the legal and regulatory approvals necessary to permit DER Monitor/Manage and will make a separate filing for such approvals, including any tariff changes to require compliance with the Institute of Electrical and Electronics Engineers Standards Association ("IEEE") 1547-2018.

[7] See U.S. Energy Information Administration, 2017 Data, Energy-Related CO2 Emission Data Tables, at Table 34 (State energy-related carbon dioxide emissions by sector) (Released May 20, 2020), https://www.eia.gov/environment/emissions/state/

level of DER adoption in the State. In other words, regardless of whether DER adoption meets the Company's forecasts, these Foundational Investments would provide flexibility over the future-term to adjust to changing circumstances and technological breakthroughs, while also delivering significant operational benefits and cost savings opportunities for customers.

This GMP, therefore, is a critical complement to the Company's recently filed Fiscal Year ("FY") 2024 Electric Infrastructure, Safety and Reliability ("ISR") Plan (the "FY2024 Electric ISR Plan"). Due to the urgent need for these investments, the Company has included the Foundational Investments as non-discretionary investments in the FY2024 Electric ISR Plan.[8] The Company intends that the PUC and other parties in the FY2024 Electric ISR Plan docket will reference and rely upon the descriptions, explanations, justifications, and, particularly, the benefit cost analysis ("BCA") contained in this GMP when evaluating the FY2024 Electric ISR Plan, as well as future electric ISR plans.

The Company will propose all the grid modernization investments necessary to implement the GMP through the ISR plan process. Consequently, the Company does not seek PUC approval for any particular investments or seek any cost recovery as part of this GMP. Rather, the GMP is an informational guidance document that supports the Foundational Investments proposed in the FY2024 Electric ISR Plan and will support additional grid modernization investments to be proposed in future electric ISR plans.

Second, this GMP describes the future vision for grid modernization with a roadmap of future grid modernization proposals (referred to as the "future-term investments"). The future-term investments will extend the capabilities provided by the Foundational Investments to leverage energy storage and advanced grid technologies that can incrementally evolve in alignment with future DER adoption. The GMP demonstrates how the Foundational Investments provide not only the needed functionality necessary for the Company to continue to deliver and enhance safe and reliable service for customers today, but also how those investments enable greater functionalities to deliver greater benefits for Rhode Island customers when integrated with additional investments in the future. For the near and future proposals, the Company has provided a comprehensive BCA demonstrating the promise of significant value from the future capabilities provided – for operations, customers, and society as a whole. The Company intends that this GMP will continue to serve as a resource in the future when it proposes these investments.

[8] Many factors support the conclusion that the Foundational Investments are urgent, including: (i) deteriorating reliability trends; (ii) a lengthening distributed generation interconnection queue; (iii) increased operational risk because of hidden load during switching; (iv) voltage variability; (v) lack of situational awareness as evidenced during the August 2022 Nasonville event; (vi) high DER adoption rates reinforced by the Climate Mandates[8] and various incentives; and (vii) a compromised supply chain, resulting in imminent delays for material availability.

Third, the Company submits that the GMP complies with its obligation under the Amended Settlement Agreement ("ASA") approved in Docket No. 4770 to file a GMP containing numerous specific components. This GMP includes all applicable[9] components required under the ASA, as summarized in Figure 1.1. In particular, Attachment A to this GMP includes "transparent, updated benefit cost analyses that fully incorporate the Docket 4600 framework" as described in Section 8 of this. The only approval the Company seeks from the PUC in filing this GMP is an order affirming that the Company has complied with its obligation to file a GMP that meets the requirements of the ASA.

In summary, and as detailed throughout this document, implementation of this GMP is critical for safe and reliable service, to provide benefits that otherwise would not be accessible to customers, to improve grid operations to enhance the quality of overall distribution service provided to customers, and to deliver on the Climate Mandates. As thoroughly demonstrated by the BCA, the investments are cost effective, regardless of whether they are analyzed on a net present value basis, nominal basis, or even looking only at the utility benefits (and not customer or societal benefits).[10] The alternative of not moving forward with these investments is likely to create higher costs and lower-level customer service, safety, and reliability, both now and in the future. Further, PPL's experience in deploying grid modernization investments in Pennsylvania over the last decade bolsters the confidence that the PUC and all stakeholders can have in the Company's ability to deliver on the benefits that will come from these investments.

[9] Because the PUC approved the ASA when the Company was owned by National Grid USA, there was a requirement to provide an "explanation of congruency with grid modernization activities in New York and Massachusetts." Because the Company is now owned by PPL Rhode Island Holdings, LLC, and is an indirect subsidiary of PPL, it is no longer affiliated with utilities operating in New York and Massachusetts. Accordingly, this requirement under the ASA is no longer applicable. The Company has, however, included significant discussion of how it will benefit from the grid modernization activities already underway in other PPL Corporation-affiliated utilities.

[10] PPL is bringing a basic advanced distribution management system ("ADMS") system (referred to herein as "ADMS Basic") to Rhode Island Energy as part of Rhode Island Energy's transition to PPL's systems. ADMS Basic is the ADMS platform PPL currently has in place for PPL Electric in Pennsylvania and which Rhode Island Energy will have in place for its operations upon exit from the Transition Services Agreement ("TSA") with National Grid USA Service Company, Inc. ("National Grid Service Company") PPL committed that the Company would forego potential recovery of any and all transition costs for moving from National Grid ownership to PPL ownership. Part of that transition includes bringing ADMS Basic to Rhode Island Energy. Accordingly, PPL is providing the ADMS Basic platform to Rhode Island Energy, the allocated costs of which will not be recovered from Rhode Island customers. ADMS Basic is an enhancement from the National Grid distribution management system. PPL and Rhode Island Energy plan to propose enhancements to ADMS Basic as part of the GMP (which are not a part of the transition) to increase functionalities and benefits. The defined term "ADMS Basic" refers specifically to the software that PPL is providing to Rhode Island Energy as part of the transition.

Section 1

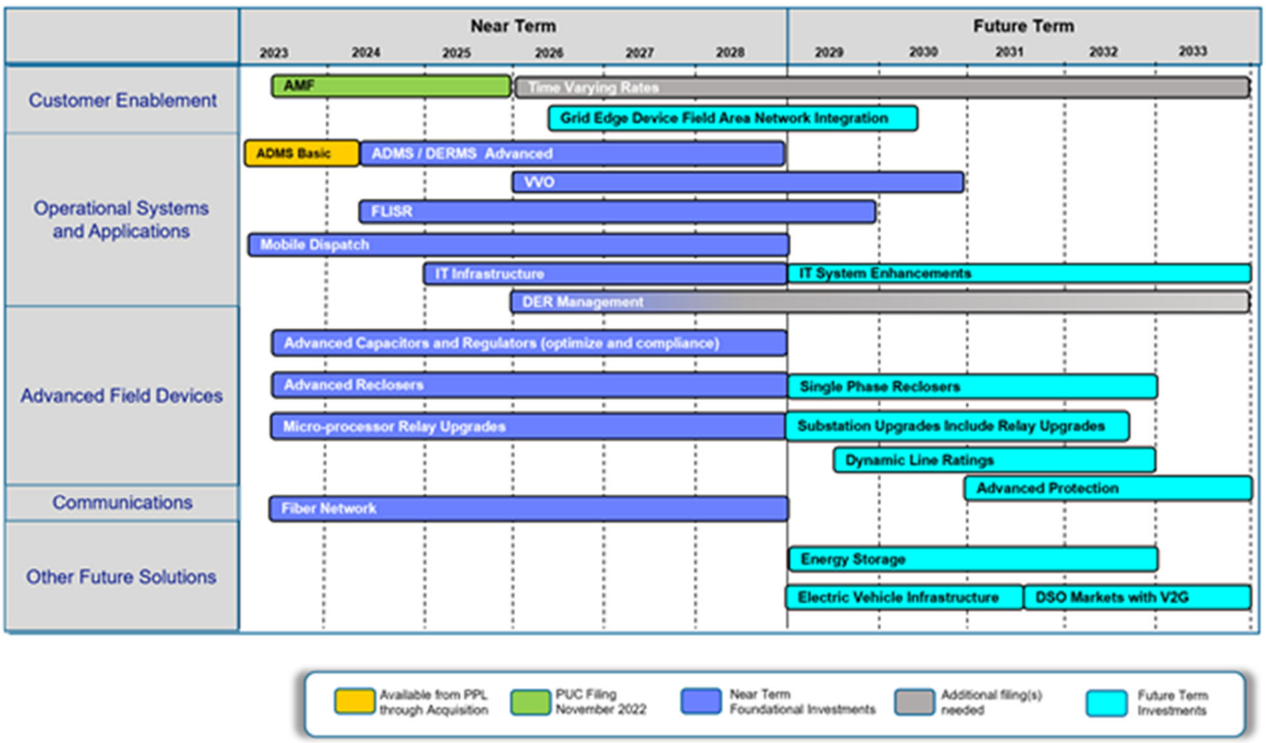
SECTION 1: Introduction

This Section presents the purpose and approach to the Rhode Island Energy GMP filing and the urgent need to act now. The Section summarizes the regulatory history for the GMP in Rhode Island and includes a table that summarizes elements called for by the ASA along with identification of where those elements are included in the GMP. This Section also describes the strategy outlook, goals and expected outcomes for GMP and the importance of GMP to achieving the State's Climate Mandates.

1.1 The GMP Purpose and Approach

Rhode Island Energy is filing this GMP in compliance with Article II, Section C.15 of the Amended Settlement Agreement ("ASA") approved in Docket No. 4770/4780. One of the fundamental purposes of the GMP is to provide the Company with the tools and capability for greater operational visibility to manage the electric distribution system more granularly considering a range of DER adoption levels, accelerated by the Climate Mandates, while at the same time maintaining a safe and reliable electric distribution system. A key focus for the Company is the urgent need to address the operational challenges surrounding reliability, safety and customer satisfaction stemming from existing and future intermittent DER's, and to improve service reliability and customer service. To that end, this GMP presents a comprehensive roadmap of the Foundational Investments that Rhode Island Energy expects will be necessary in the near term (i.e., next 6 years) to ensure the safe and reliable operation of a modernized grid, and future-term investments (i.e., through 2042) that will extend the capabilities of the Foundational Investments to leverage energy storage and advanced grid technologies that can incrementally evolve over time commensurate with future DER adoption. These investments are summarized in the GMP roadmap, Figure 1.0.

Figure 1.0: Rhode Island Energy Grid Modernization Solutions Roadmap



This GMP is intended to serve as a supplement and necessary complement to the annual electric ISR plan review process. A description of the GMP Foundational Investments being proposed in the FY 2024 Electric ISR Plan is contained in Section 6 and is further substantiated with a Rhode Island specific BCA in accordance with the framework that the PUC adopted in Docket No. 4600 (the "Docket 4600 Framework"),[11] as discussed in in Section 8.

As discussed in the Executive Summary, the Company is not seeking PUC approval of any particular investments or seeking any cost recovery as part of this GMP. Rather, the GMP is an informational guidance document that supports the Foundational Investments proposed in the FY2024 Electric ISR Plan and will support additional grid modernization investments to be proposed in future electric ISR plans. Accordingly, the only approval the Company seeks from the PUC in filing this GMP is an order affirming that the Company has complied with its obligation to file a GMP that meets the requirements of the ASA.

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[11] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 at 23 (July 31, 2017).

This GMP includes a summary of the operational challenges occurring on Rhode Island Energy's electric distribution system as a result of the high penetration of DER; a summary and results of a comprehensive long-range Distribution Study and a Transmission Study[12]that analyzed the Rhode Island Energy electric system to meet the Climate Mandates and included a review of the alternatives considered, a reliability analysis, a Rhode Island-specific BCA in accordance with Docket 4600 Framework; and a roadmap with a deployment plan for the required investments. The GMP considers PPL's mission and experience deploying grid modernization in its other service territories.

Investments in grid modernization based on a well-coordinated and integrated GMP will allow for an expanded toolbox of solutions to the complex issues arising from high DER penetration and customers' desire for choice and control over their energy needs. GMP investments will allow the Company to not just interconnect, but to integrate DER into distribution system operations reliably and safely for the benefit of all customers.

1.2 Amended Settlement Agreement Resolving Docket Nos. 4770 and 4780

In November 2017, the Company applied for approval of changes in electric and gas base distribution rates in Docket No. 4770 ("2017 Rate Case"),[13] along with a Power Sector Transformation (PST) Vision and Implementation Plan ("PST Plan").[14] The PST Plan proposed a suite of investments, including grid modernization solutions and state-wide deployment of Advanced Metering Functionality ("AMF"), to modernize the State's energy infrastructure. On August 16, 2018, the Company, the Division of Public Utilities and Carriers ("Division"), the Rhode Island Office of Energy Resources ("OER"), along with the other intervening parties filed the ASA[15] that resolved all disputed issues in both dockets, which the PUC approved on August 24, 2018 in Docket Nos. 4770 and 4780.[16]

[12] The "Distribution Study" includes distribution and sub-transmission system infrastructure (400 distribution feeders, 56 sub-transmission lines, and associated substations). It analyzed two alternatives to determine avoided infrastructure and other benefits from grid modernization as described in the GMP resulting in the most efficient investment plan to meet the state's Climate Mandate while serving Rhode Island customers reliably and safely. The "Transmission Study" is a separate bulk transmission study (345- and 115-kV system) utilizing the results from the Distribution Study to determine the impacts to the bulk system.
[13] *See* The Narragansett Elec. Co. d/b/a National Grid, Application for Approval of a Change in Elec. and Gas Base Distribution Rates, Docket No. 4770 (November 27, 2017).
[14] *See id.*; *see also* The Narragansett Elec. Co. d/b/a National Grid, Proposed Power Sector Transformation (PST) Vision and Implementation Plan, Docket No. 4780 (November 28, 2017) (Following review of the filings, the PUC docketed the rate case and PST Plan filings separately.).
[15] *See* Amended Settlement Agreement ("ASA"), Docket No. 4770 (August 16, 2018).
[16] *See* Report and Order No. 23823, Docket Nos. 4770 and 4780 (May 5, 2020).

The ASA included an initial, limited set of grid modernization investments as part of a multiyear rate plan ("MRP"),[17] and further required the Company to file a comprehensive GMP and Updated AMF Business Case, which describes how each integrates with the other.[18] The GMP must provide a full assessment of the various initiatives contemplated by the Company, including an explanation and evaluation of how the initiatives link to each other (*see* Section 6). The ASA also required the Company to assess both short and long-term initiatives and to present implementation plans outlining the details and technologies over a five-year horizon, plus an outline of how the GMP aligns with a ten-year roadmap (*see* Section 6 and Attachment H Deployment Plan).

In addition, the ASA includes twelve requirements for the Company to address in the GMP, including a transparent, updated BCA that fully incorporates the Docket 4600 Framework.[19] The ASA requirements applicable to GMP are listed below in Figure 1.1. Rhode Island Energy has incorporated all requirements from the ASA into this GMP except for number 13, below (requiring an explanation of congruency with grid modernization activities in New York and Massachusetts) because this requirement is no longer applicable in the context of PPL ownership.[20] For convenience, the right column notes the Section(s) in this GMP where each element in the ASA is addressed.

[17] The MRP was extended with the consent of the Division. See National Grid – Notification of Agreement between the Company and the Rhode Island Division of Public Utilities and Carriers regarding an Extension of the Term of the Multi-Year Rate Plan (July 15, 2021).
[18] *See* ASA, Art. II, Sec. C.15, C.16.
[19] *See* ASA, Art. II, Sec. C.15.c.vi.
[20] PPL does not operate in New York and Massachusetts therefore, congruence with New York and Massachusetts is not applicable to Rhode Island Energy's GMP. While grid modernization is in different stages of maturity in PPL's other jurisdictions (Pennsylvania and Kentucky), this GMP discusses the ways in which PPL's experience and insights with successfully installing grid modernization technologies over the past decade can be leveraged for Rhode Island.

Figure 1.1: Amended Settlement Agreement Terms Mapping to GMP Section

ASA Grid Modernization Terms	GMP or Other GMP Document Sections
1. Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket 4600 Guidance Document;	• Section 1.4: BCA Summary
2. Explanation of the role of currently active programs ;	• Section 2.3: Current Grid Modernization Activities
3. Investments and technology deployments planned through the end of any proposed AMF implementation;	• Section 1 • Section 6
4. Functionalities to achieve the objectives;	• Section 3: Functionalities Needed to Transform the Grid
5. Review of options for candidate technologies to deliver those functionalities;	• Section 3 • Section 4 • Section 5 • Attachment H Deployment Plan: all sections • Updated AMF Business Case (separate filing)
6. Transparent, updated benefit cost analyses that fully incorporate the Docket 4600 framework;	• Section 8: BCA Evaluation Under Docket 4600 • Attachment I: Benefit Cost Analysis Details
7. An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments;	• Section 6 • Section 1.9 • Attachment H Deployment Plan: all sections
8. A plan and explanation for the integration and leveraging of customer-side	• Section 6.2: GMP Roadmap – Customer Enablement

technologies and resources in the near and long-term;	• Section 6.6: GMP Roadmap – Other Future Solutions
9. Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities;	• Section 6.5: GMP Roadmap: Communications
10. Explanation of congruency with grid modernization activities in New York and Massachusetts;	• Not applicable
11. A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; and	• Section 7.1: Managing Risk of Redundancy, Obsolescence, and Uncertainties
12. A description of how the GMP, in particular the distribution planning components, addresses the relationship between electrification of heating and transportation and energy efficiency to allow for the furtherance of overall reduced peak demand while also encouraging electrification of heating and transportation.	• Section 5 • Section 3.5 GMP impacts to load management capability

In summary, the GMP satisfies the requirements of the ASA approved in Docket No. 4770.

1.3 Stakeholder Engagement

The ASA also required an engagement with stakeholders via a newly created PST Advisory Group or relevant subcommittee to develop the AMF Business Case and GMP. Through the PST Advisory Group, an AMF/GMP Subcommittee was launched in October 2018.[21] The Subcommittee engaged over the course of numerous meetings between October 2018 and December 2022.[22] Rhode Island Energy

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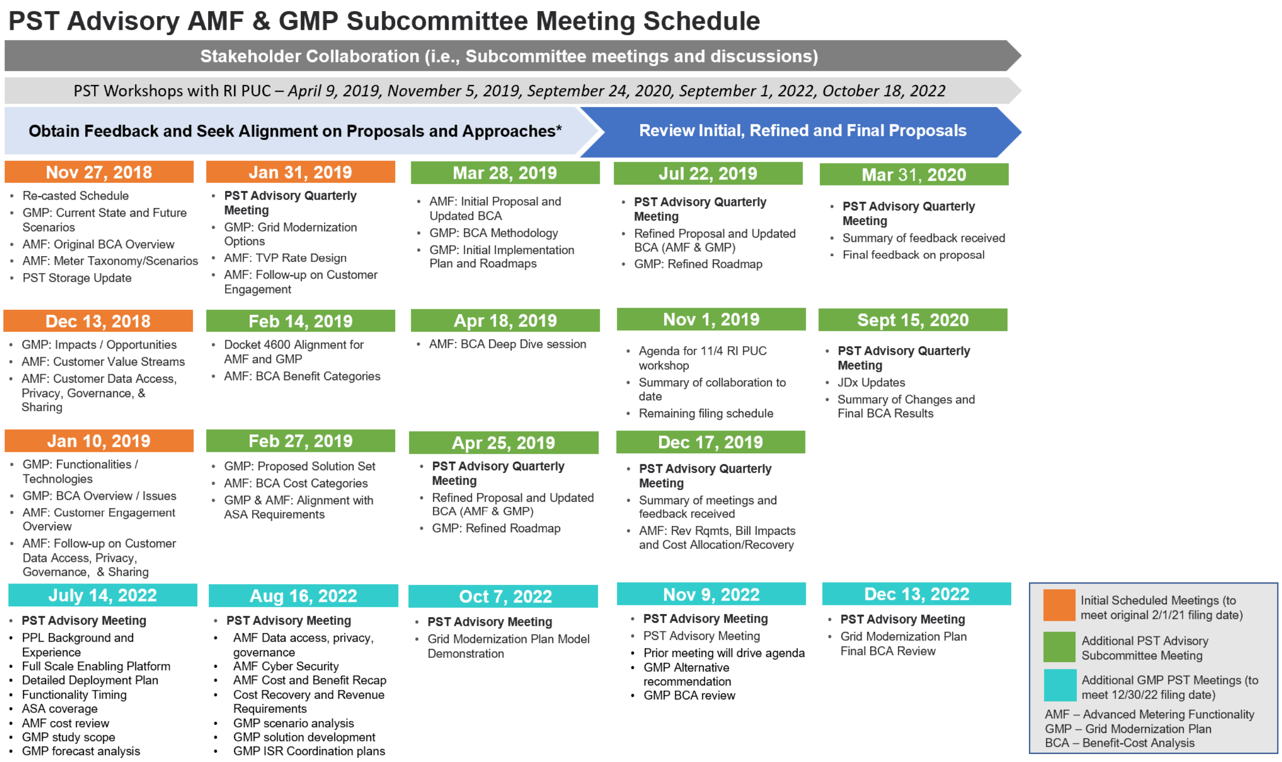
[21] The PST Advisory Group Subcommittee members represent a broad spectrum of interests ranging from environmental and clean-energy groups to low-income, community, and business interests, as well as Non-regulated Power Producers ("NPPs").

[22] The PST meetings were sequenced such that the first set of meetings focused on detailed topical discussions of components contained in the National Grid's Updated AMF and GMP filings. Following these meetings, a set of milestone

reviewed the power points and minutes from the prior PST meetings and interviewed employees who were in attendance to gain an understanding of history and input that was provided. The Company also arranged additional PST meetings to get input on the GMP analysis in July, August, October, November, and December of 2022 in preparation for this filing. The input received during these meetings resulted in several contributions that are reflected in this GMP such as the GMP study process and assumptions, time-variable rate ("TVR") interests, and a variety of inputs for the BCA assumptions. Stakeholder input also identified several topics that were expanded upon and discussed in greater detail such as the DER forecast assumption to meet the Climate Mandates, modeling used to determine the difference in infrastructure needed with and without GMP, impacts of offshore wind on this analysis and conclusions, and the strategy regarding energy storage. Figure 1.2 below illustrates the PST Advisory AMF/GMP Sub-committee Meetings, including those PST meetings that were specific to the GMP.

meetings were held to review National Grid's Updated AMF Business Case and GMP, A similar approach was used in 2022 with the PST AMF/GMP Subcommittee in preparation for this GMP filing. Initially, the GMP study scope and approach were discussed along with the methodology for the DER forecast to meet the Climate Mandates. Later, scenario analysis, solution develop and ISR coordination was discussed. In response to PST AMF/GMP Subcommittee feedback, the Company provided a demonstration of the CYME 8760-hour modeling. Toward the end of the planning process, the PST Advisory Group Subcommittee was briefed on the BCA approach, reviewed the recommendations that came from the GMP alternative analysis, and provided an opportunity to discuss all GMP elements prior to the GMP filing.

Figure 1.2: PST AMF / GMP Sub-Committee Meetings Featuring GMP



1.4 BCA Summary

In developing the GMP BCA, Rhode Island Energy built upon the National Grid BCA that was developed using the Docket 4600 Framework and filed with the PUC in January 2021. Rhode Island Energy enhanced the BCA with data and experience from PPL's GMP investments over the last decade. To ensure a comprehensive BCA that covers all potential benefits and costs introduced by grid modernization, Rhode Island Energy: (1) conducted workshops with key internal and external personnel, (2) reviewed and participated in industry and government forums, (3) gathered data to refine the scope of the GMP investment; (4) gathered relevant use cases from PPL and across the industry; (5) evaluated pertinent PPL operational data pre- and post-GMP implementation; (6) conducted extensive independent research on different aspects of the scope of benefits and costs; and (7) developed and finalized the key benefits of the BCA.

A detailed BCA, which compares the costs and benefits of the infrastructure that will be needed to meet the Climate Mandates in 2050, assuming grid modernization investments are installed (referred to herein as the "Grid Modernization alternative"), as the "reference case", with the infrastructure that will be needed without grid modernization investments (i.e., traditional investments only) (referred to herein as the "No Grid Modernization alternative"). The Company's BCA is consistent with the Docket 4600 Framework and is discussed in detail in Section 8: BCA Evaluation Under Docket No. 4600. Through this engagement and research, the Company was able to quantify important grid modernization benefits and costs, and when quantification was not possible, the Company included a discussion of qualitative benefits. The Company utilized a detailed state-wide and feeder-level modeling of the 2050 future state scenarios that achieves the State Climate Mandates and well-established BCA methodologies and input assumptions to quantify benefits.

The value of the proposed Grid Modernization investments for Rhode Island is captured in both the quantitative and qualitative components of the BCA. The BCA quantifies future state scenarios defining infrastructure required to serve a modern-day grid that can host the level of DER needed to achieve the Climate Mandates by 2050 to show that the alternative with grid modernization investments is best. As shown in Figure 1.3 below, over a 20-year evaluation period, Rhode Island Energy expects to invest \$529 million Nominal and \$373.8 million on a \$2023 Net Present Value ("NPV") basis. Over the 20-year life of the GMP Foundational Investments, Rhode Island Energy expects Rhode Island utility benefits, customer benefits and societal benefits of \$3.9 billion Nominal and \$2.5 billion NPV (\$2023). This results in a net value of benefits minus costs of \$3.4 billion Nominal and \$2.2 billion NPV (\$2023). The benefit-cost ratios are 7.5 Nominal and 6.8 NPV. This BCA assumes the full suite of Foundational Investments are made, and the full-scale AMF deployment is approved and implemented as filed in November 2022.

Figure 1.3: Benefits and Costs of Grid Modernization Alternative

GMP Benefits and Costs				
As of December 22, 2022				
Category	**Nominal ($M)**		**NPV ($M)**	
Utility	**$**	**2,928.8**	**$**	**1,768.6**
Direct Customer	**$**	**527.7**	**$**	**377.1**
Societal	**$**	**490.4**	**$**	**379.1**
Total Benefits	**$**	**3,946.9**	**$**	**2,524.7**
Total Costs	**$**	**529.0**	**$**	**373.8**
Benefits Less Costs	**$**	**3,417.8**	**$**	**2,151.0**
B/C Ratio	**7.5**		**6.8**	

The quantitative BCA results in just over 2 billion dollars in net benefits for Rhode Island customers on a 20-year NPV ($2023) basis. Benefits exceed costs for all alternatives and all benefit to-cost ratios are well above one. A positive GMP benefit-cost ratio results through all cost, benefit and time sensitivities that were tested and also holds true if Utility Benefits are considered in isolation. Because the proposed Foundational Investments are needed now and for any DER adoption rate in the future, and the decision results in a positive financial outcome under any scenario, Rhode Island Energy refers to these Foundational Investments as a "No Regrets" path for grid modernization in Rhode Island.[23] The GMP demonstrates that the "No Regrets" decision provides a net benefit under any future scenario. Furthermore, the proposed "No Regrets" approach provides a confidence in moving forward on a path that is known to have uncertainties, aligns stakeholders to a course of action, addresses unmet needs that are evident now and will become more evident in the future, provides opportunities to establish a basis where adjustments can be made over the long term to deliver the highest value, and provides an avenue

[23] The term "No Regrets" is used in planning and in the BCA to indicate a decision or an investment that will be used and useful in virtually any future scenario that may emerge. As used throughout this GMP, "No Regrets" investments are investments, such as the Foundational Investments, that are required regardless of the future levels of DER penetration on the system.

to take concrete action which will fosters a belief in capabilities thereby minimizing "freeze" effects that are often triggered by uncertainty associated with vague circumstances.[24]

The Docket No. 4600-A PUC Guidance Document (the "Docket 4600 Guidance Document") specifies that any proponent of a program proposal with associated cost recovery will need to meet the Docket No. 4600 goals, principles, and framework[25]. The Docket No. 4600 goals embrace the important question of "What can, and should the new electric system be able to accomplish?" Evaluation of these expectations and goals resulted in three key GMP objectives. Figure 1.4 shows the alignment between the Docket No. 4600 goals and GMP objectives.

Figure 1.4: Alignment Between Docket No. 4600 Goals and Rhode Island GMP Goals

<table>
<tr><th>Docket No. 4600 Goals</th><th>GMP Goals</th></tr>
<tr><td>Address the challenge of climate change and other forms of pollution</td><td rowspan="2">1) Build a flexible, safe, reliable modern-day grid to integrate more clean energy generation</td></tr>
<tr><td>Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive</td></tr>
<tr><td>Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits</td><td rowspan="3">2) Give customers more energy choices and information</td></tr>
<tr><td>Appropriately charge customers for the cost they impose on the grid</td></tr>
<tr><td>Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society</td></tr>
<tr><td>Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)</td><td rowspan="3">3) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term</td></tr>
<tr><td>Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures</td></tr>
<tr><td>Appropriately compensate the distribution utility for the services it provides</td></tr>
</table>

[24] No Regret Decisions: The First Steps of Leading through Hyper-Change | Human-Centered Change and Innovation, https://bradenkelley.com/2021/09/no-regret-decisions-the-first-steps-of-leading-through-hyper-change/
[25] Docket 4600 Guidance Document, supra note 9 at 2.

While this GMP is not seeking cost recovery at this time, the Company has provided an explanation of how the GMP advances, detracts from, or is neutral to each of the goals for the "new" electric system, as outlined in Docket No. 4600, in Attachment A, Figure A.1. Additional discussion is included in Section 8 of this GMP.

1.5 Grid Modernization Is Needed to Meet Rhode Island's Climate Mandates

This GMP reflects the significant changes that are occurring across Rhode Island Energy's electric system because of the State's Climate Mandates to achieve net-zero carbon emissions by 2050 and 100 percent renewable energy by 2033. These changes are marked by the increasing adoption of additional renewable generation sources, including DER. This GMP also contemplates increasing availability of beneficial electrification, EVs, EHPs, and advanced "smart" technologies to actively manage energy use in customers' homes and places of businesses. Adoption of DER is critical to enabling customer empowerment and meeting the Climate Mandates because it will enable customers to reduce their overall emissions, including transportation- related emissions that make up 40% of the State's carbon dioxide ("CO2") emissions[26]; however, interconnecting DER into the existing electric distribution system infrastructure is becoming increasingly complex and expensive. Rhode Island needs a well-coordinated and integrated grid modernization strategy now to meet the operational and customer needs while providing modern-day infrastructure capable of achieving the Climate Mandates safely and reliably. Grid modernization investments will help reduce the costs and other barriers to interconnect new DER in Rhode Island, which will drive more DER adoption and investment in the State.

Without grid modernization, the clean energy transition cannot happen at the pace and magnitude that is set forth in the Climate Mandates. If the Company takes a "do nothing" approach and does not invest in well-coordinated and integrated grid modernization investments, increasing interconnection costs will slow renewable DG adoption rates below the current level, EV charging infrastructure will be more costly, and customer participation in and impact from future DER and energy efficiency programs will be limited. The safety and reliability of the system will also be at risk because operators will lack necessary visibility and control of dynamic grid conditions. Therefore, the consequences of a "do nothing" approach will put the State's ambitious Climate Mandates out of reach.

1.6 Grid Modernization Is Needed for the "Modern-Day" Grid

Operationally, grid modernization is needed now. The Company refers to a "modern-day" grid in this GMP as a distribution system that is subject to the mismatch between renewable contributions and peak

[26] See U.S. Energy Information Administration, 2017 Data, Energy-Related CO2 Emission Data Tables, at Table 4 (State energy-related carbon dioxide emissions by sector) (Released May 20, 2020), https://www.eia.gov/environment/emissions/state/.

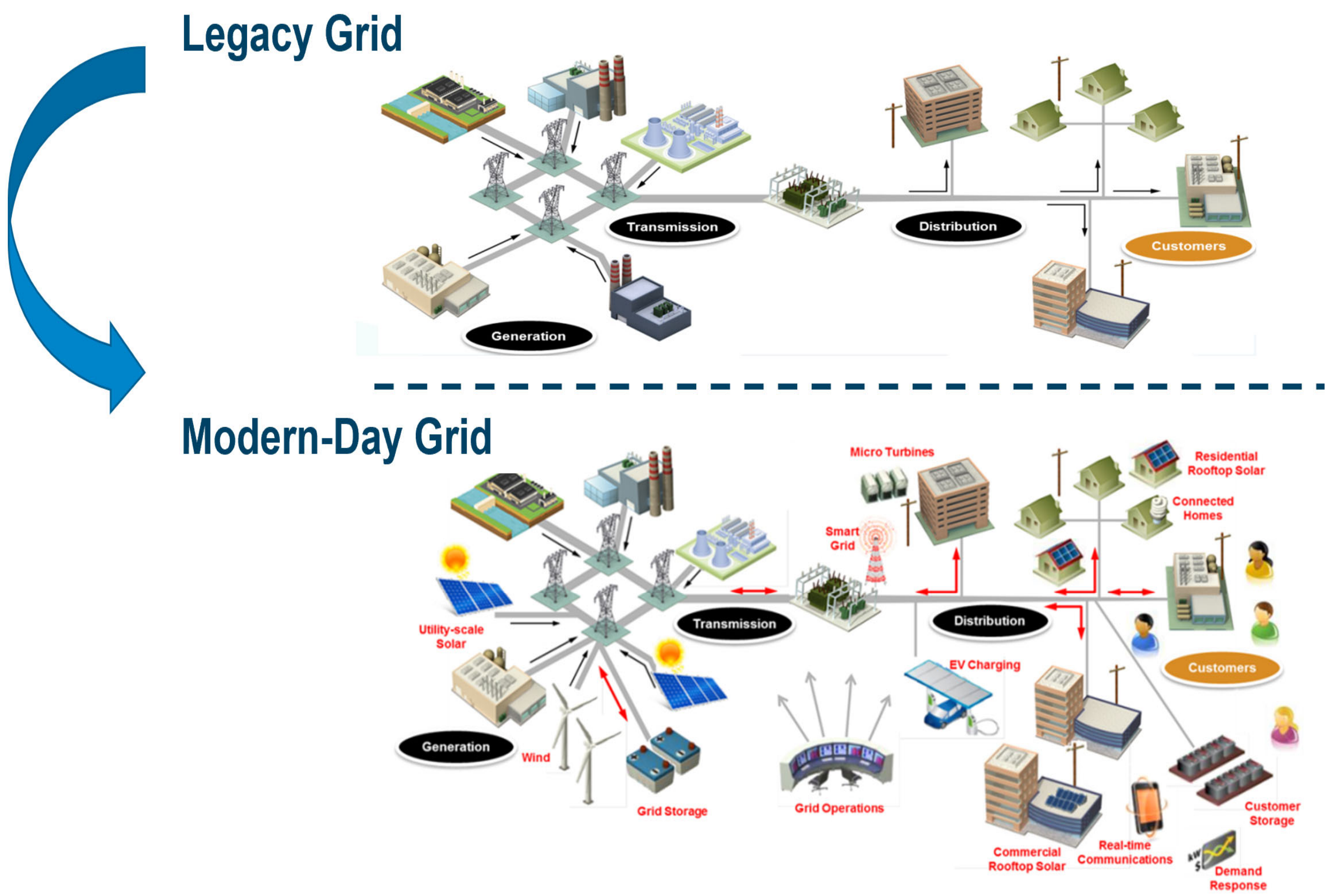
load, two-way power flow, and dynamic performance characteristics from hosting DER as explained more fully in this section.

The legacy distribution system has been designed and operated as a radial, one-way power flow system. While modifications have been made in certain instances to accommodate DER, the fundamental design, protection, control, and operation have assumed that power was flowing from the generation source to the load as shown in the top portion of Figure 1.5 below. When faults occur on a distribution feeder (lightning strike, tree in line, broken cross-arm, etc.) the substation relays detect the fault, customers call in their outages and crews are dispatched to investigate, manually isolate and make repairs. The trends discussed in Section 1.5 above, are accelerating a shift from the original one-way flow of electricity from the utility distribution system to the customer, to two-way power flow that is more dynamic and less predictable. Two-way power flow occurs when customers both consume and produce electricity at distribution system locations that were historically points of delivery. Legacy electric distribution equipment has used local control settings that operate autonomously without remote monitoring or real-time controls; the emerging characteristic of two-way flow of information and energy requires the Company to have greater visibility, more granular control of the distribution system, and increased ability to communicate energy usage information to customers to operate safely and reliably.

Additional system complication occurs because DER injections from renewable generation does not fully coincide with traditional electric load. For example, solar DG output typically peaks between 11 a.m. and 1 p.m. while the traditional electric load peaks between 5 p.m. and 7 p.m. on the hottest days of the summer. Residential EV charging is also likely to occur between 5 p.m. and 7 p.m. when customers return home from work. Therefore, traditional load coupled with growing EV charging will raise peak demand, especially on hot summer days and contributions from solar and wind DG will continue to reduce minimum load periods (e.g., 11 a.m. until 1 p.m. especially in the early spring). These changes are already creating high-voltage issues on parts of the Rhode Island distribution system that will continue to exacerbate as DER penetration increases. Furthermore, unmanaged EV charging will likely increase the peak from 5 p.m. until 7 p.m. in the summer which can create low-voltage and thermal overload issues on the distribution system. The mismatch between renewable DG injections and peak load periods can result in large voltage swings, unforeseen dynamic system performance conditions and thermal overloads that need to be managed and mitigated for Rhode Island Energy to provide distribution-level grid reliability, as well as system, worker, and customer safety and security.

As shown in Figure 1.5, the modern-day grid is much more complex and less predictable for a variety of reasons requiring the added functionality from grid modernization technologies to provide the necessary visibility and system control for a safe and reliable system. With grid modernization investments, DER integration with the electric distribution system occurs in four progressive levels resulting in "The DER-Dependent Grid" where DER are mission-critical assets required for safe and reliable grid operations.[27]

Figure 1.5: Grid Transformation

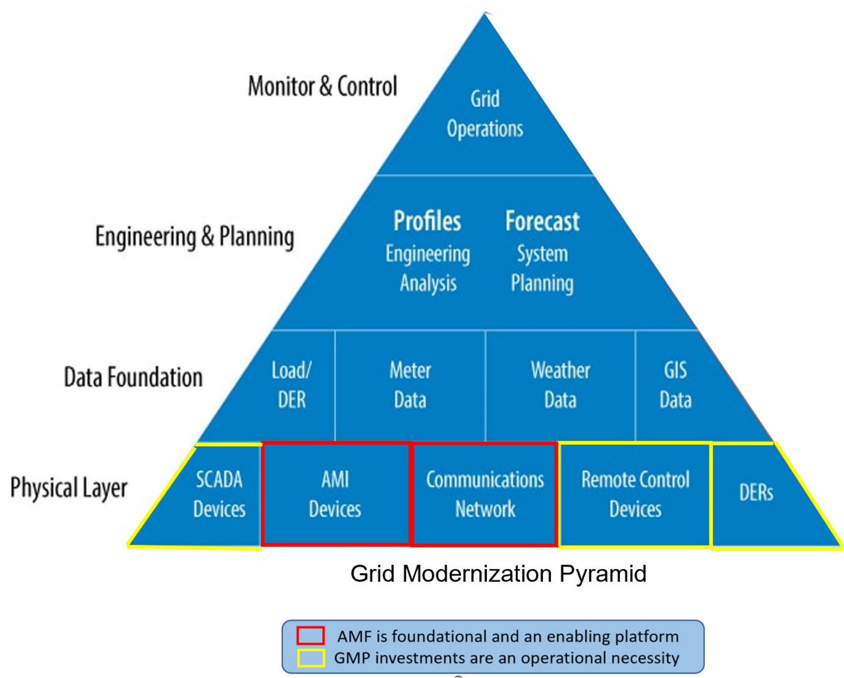


[27] *See Maximizing Distributed Energy Resource Value Through Grid Modernization*, Electric Power Research Institute (Aug. 2021) http://mydocs.epri.com/docs/public/EPRI-Report-MaximizingDistributedEnergyResourceValue-20210804.pdf.

1.7 Grid Modernization Pyramid and Expected Outcomes

As provided in Section 1.4, the GMP objectives address the needs to operate the modern-day grid flexibly, safely and reliably, addressing emerging customer expectations, and meeting the Climate Mandates. The grid modernization pyramid[28] shown in Figure 1.6, below, illustrates how the integration of grid modernization investments provide the necessary visibility and enhanced distribution control for modern-day grid operations that is flexible, safe and reliable. The first step to grid modernization is represented by the Physical Layer in Figure 1.6, which involves digitizing physical assets, such as meters and distribution devices, by equipping them with remote monitoring and control features. The AMF Business Case that the Company submitted in November 2022 proposed this digitization for Rhode Island Energy's electric meter assets; this GMP is proposing digitization for key distribution assets that will be enhanced by the integration of granular information provided by the AMF meters. Information from along the feeder forms a network model made from thousands of supervisory control and data acquisition sensors ("SCADA") and AMF devices located from the meter into the substation that is frequently processed, stored, and analyzed to provide increased system visibility and control.

Figure 1.6: Grid Modernization Pyramid



[28] *See* https://www.infosys.com/iki/perspectives/clean-energy-future.html

As the penetration of DER increases, their impacts on grid operations—both positive and negative—will also increase. Without adequate planning and grid modernization functionality for operations, the proliferation of DER will significantly compromise power reliability. To realize the full value of DER, the distribution system components must become more *visible in real time* so distribution system operators are aware of the DER presence and their characteristics, such as rated capacity and power imports or exports over time. Visibility makes distribution system operators aware of the effects of DER on the grid but does not provide any ability to manage those effects. If the DER are also *controllable,* impacts can be addressed more directly. Where DER are both visible and controllable, their operation can be managed to minimize negative impacts to the grid while optimizing the benefits to DER-owning customers and to other customers. Visibility and controllability are prerequisites for *integrating* DER into the grid to realize their full potential, which is explained in greater detail in Attachment G, This GMP proposes DER Monitor/Manage as a strategically important GMP functionality because it brings operators the necessary visibility and control of DER so they can be fully integrated and considered a valuable part of the distribution system.

Expected outcomes, or benefits from the Foundational Investments included in this GMP include:

- **Increased Visibility and Situational Awareness of the Distribution System**: The GMP will expand capabilities in monitoring, sensing, communication, and control, which increase grid visibility, situational awareness, data collection, and the ability to respond to varying grid conditions and anomalies in real time. These capabilities simultaneously support reliable and safe operations, de-carbonization, increased resiliency, and enable greater DER market growth.
- **Enable lowest-cost development of the Transmission and Distribution System**: The Distribution Study (*see* Section 5) demonstrates that GMP technology and functionality can significantly reduce the cost of providing transmission and distribution ("T/D") infrastructure. For example, demand on individual feeders can be shifted through automatic sectionalizing; voltage can be controlled and optimized; and DER Monitor/Manage can be used to manage thermal loading and reduce curtailment. The Distribution Study shows that $1 billion in infrastructure can be avoided over the next 30 years due to the capability of GMP and associated distribution automation that is enhanced with information from AMF.
- **Improved Reliability** – Rhode Island's distribution system reliability has been declining as discussed in Section 1.9, below. This trend is forecasted to reverse with the GMP investment in Fault Location Isolation and Service Restoration ("FLISR"). FLISR will remotely identify faults, isolate the trouble, and automatically restore service to many customers which is forecasted to improve reliability up to 30%. PPL Electric has implemented this functionality at full scale in Pennsylvania and in doing so, significantly improved reliability in Pennsylvania as explained in Section 1.8.
- **Optimize DER Energy Production** – The "Reference Case" without grid modernization investments in the Distribution Study assumes the Company would need to curtail renewable

DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the design limitations of the system. This results in an average renewable DG seasonable curtailment of 17.7% of its annual energy output by 2030 and increase in subsequent years. DER Monitor/Manage GMP functionality ramps individual DER up or down with an Advanced Distribution Management System ("ADMS") application, which reduces DER curtailment from approximately 17.7% to less than 1% of annual energy output per year. This functionality will maximize renewable energy production to contribute towards meeting the State's Climate Mandate.

- **Reduce Operations and Maintenance ("O&M") Costs** – GMP use cases from PPL Electric and other utilities have demonstrated significant reductions in O&M expenses from items such as dispatching efficiencies, avoided truck rolls, and avoided telecom fees.
- **Reduce Peak Demand and Energy Costs** – Significant benefit can be achieved by using GMP to reduce and shift winter and summer peak demand using TVR, Volt VAR Optimization ("VVO"), DER Monitor/Manage, and demand response on a targeted basis. This will avoid T/D infrastructure cost and reduce ISO-NE Market costs for capacity, energy, and ancillary services.

Looking to the future, grid modernization initiatives must consider the physical grid infrastructure as DER penetration increases and the system grows. "Physical digitization investments are prerequisites to prepare the grid for future capabilities and applications, including DER. It's important to plan for grid infrastructure upgrades with an eye towards future DER deployment, as much of the infrastructure was not designed with DER in mind. As these upgrades are performed, it will be important to opportunistically digitize physical assets to advance and enhance system visibility and control of the modern-day grid over time.

1.8 Rhode Island Energy Benefits from PPL's Grid Modernization Experience

On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100% of the outstanding shares of common stock of The Narragansett Electric Company from National Grid, (the "Acquisition"). PPL has successfully installed grid modernization and AMF over the last decade and as a result, Rhode Island Energy will benefit from their insights and lessons that have been learned throughout this journey.

PPL has been nationally recognized for its successful AMF and GMP deployments as examples of technology innovation and pioneering achievements in the utility industry.[29] For example, Smart

[29] In 2019, PPL Electric won the Reliability One Best Improved Utility for Reliability based upon a measure of reliability performance data that was certified as part of the program. According to IEEE and EEI analyses, PPL Electric has performed in the first quartile for SAIFI every year for the last seven (7) consecutive years. PPL has also demonstrated capability and been repeatedly recognized for its ability to satisfy customers. According to the 2021 Sustainability Report, PPL has been awarded 58 total J.D. Power residential and business customer satisfaction awards in Pennsylvania and Kentucky combined.

Electric Power Alliance ("SEPA") recently released a Case Study summarizing PPL's lessons from deploying their Distribution Management Systems ("DMS") applications, devices, and real-time communications technology to become "DER-aware." DMS has transformed how DER interact with PPL's distribution system and has evolved into a component of ADMS, which has resulted in key considerations for other utilities.[30]

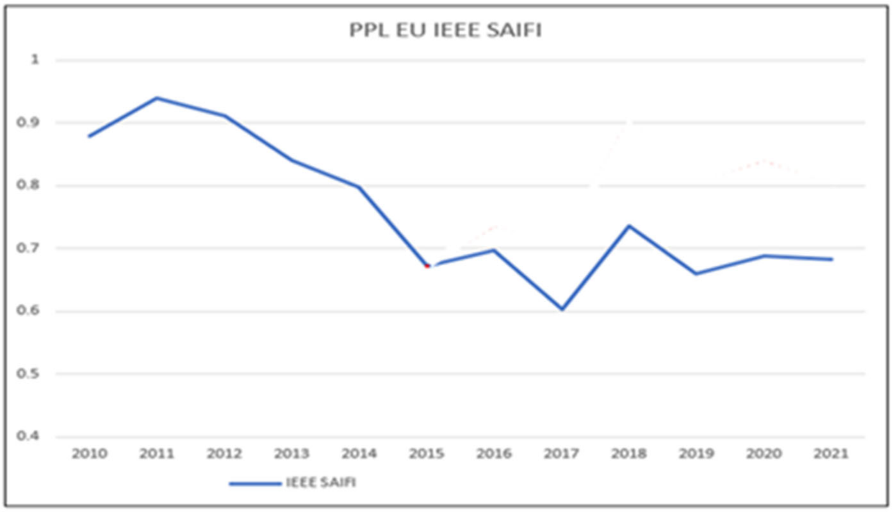
Grid modernization is in different stages of maturity in its Pennsylvania and Kentucky jurisdictions. While there are differences in timing and prioritization, the same vision of grid modernization is shared across jurisdictions and reinforced with reference standards to gain efficiencies. The control center and related back-office investments presents the greatest opportunity for synergies, including investments in ADMS and future functionality, Information Technology ("IT") infrastructure, and appropriate cyber services. Consequently, the deployment of certain solutions in the GMP would be performed by PPL as a shared service and costs will be shared and allocated across the operating companies. PPL's grid modernization experience mitigates the uncertainty of certain expected costs and benefits and facilitates synergies and savings by utilizing pre-existing integration, processes, and procedures that are proven.

PPL Electric customers have benefited from AMF and grid modernization investments in Pennsylvania. By applying the technologies in tandem, the frequency of outages or System Average Interruption Frequency Index ("SAIFI") has improved over time. As shown in Figure 1.7, below, there has been steady improvement (trending down) over the last decade after excluding IEEE Major Events. This significant accomplishment is a direct result of deploying grid modernization investments, including automation of the electric distribution grid with smart recloser installations, microprocessor relays, and more than 1.4 million second-generation automated meters.

The strong record of customer satisfaction is statistically correlated to the ability to continuously reduce the number of sustained outages that customers experience.

[30] SEPA case study - Insights_from_PPL_s_DERMS_Implementation.pdf

Figure 1.7: PPL EU SAIFI Trend Improves with Grid Modernization



PPL is a proven innovator, having been one of the first utilities in the country to systematically install FLISR technology to automatically sectionalize the electric distribution system in blocks of approximately 500 customers. This investment has changed how the distribution system operates by automating the distribution network reconfiguration, minimizing the number of customers impacted by a power outage, and enabling more effective and efficient response to restore service. FLISR automation isolates the effect of outages to small customer blocks using automated distribution switching so fewer customers experience an outage. Outage information and isolation enable restoration crews to be more efficiently dispatched to pinpointed outage locations, resulting in reduced outage restoration times. Business results are a direct result of full-scale deployment of FLISR, second-generation AMF, and supporting operational tools such as ADMS. PPL is bringing ADMS Basic to Rhode Island Energy as a condition of the Acquisition and as part of Rhode Island Energy's transition to PPL's systems. Rhode Island Energy does not intend to seek recovery of its allocated share of the costs of the ADMS Basic from Rhode Island customers.[31]

ADMS is central to the linkage between AMF and GMP. ADMS is essential for situational awareness and control wherewithal to operate a modern-day grid. Critical AMF data such as interval voltage and reactive power data, and voltage real-time alerts, will be imported into ADMS, which has the capability to selectively acquire voltage data at points of interest on the network that will aid in providing safe and reliable system operations.

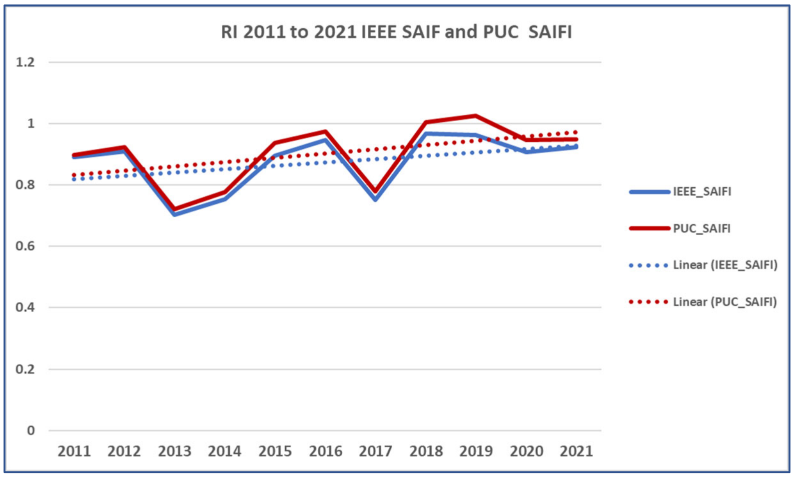
[31] *See N.* 10, *supra*.

PPL's decade of GMP experience offers the potential for efficiencies, costs savings, and functionality in Rhode Island that would have otherwise taken more time and expense to attain. The GMP incorporates PPL's philosophy for grid modernization and many insights gained, such as engineering design standards, systems integration, communication requirements, installation efficiencies, and reference standards. PPL is confident and expects that the Foundational Investments described in this GMP will result in benefits and performance gains for Rhode Island customers that will be similar to that experienced by PPL Electric customers. The GMP investment will serve as an informational platform positioning Rhode Island Energy to gather, analyze and leverage information to better operate an increasingly complex and dynamic modern-day grid with greater visibility and awareness that will help improve decision-making and offer the capability for improved system control and optimization.

1.9 Rhode Island Energy's Reliability Performance Will Pivot with Grid Modernization

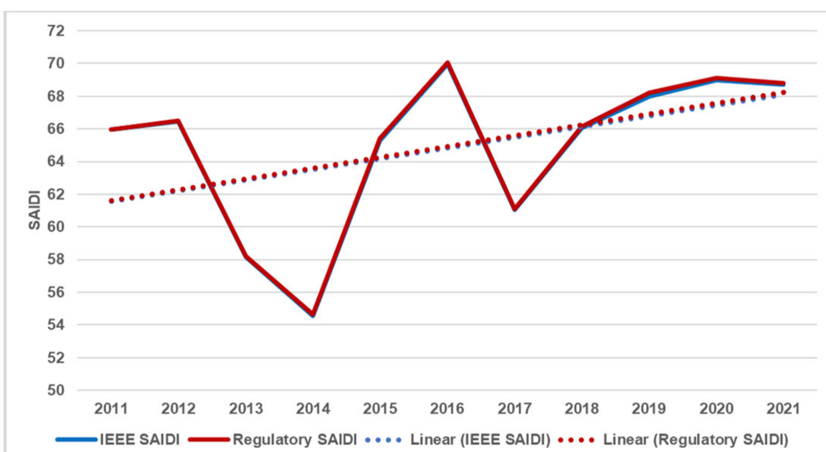
There is evidence that Rhode Island Energy's reliability performance trend has been declining over the last decade. Figure 1.8 and Figure 1.9 below show SAIFI and System Average Duration Index ("SAIDI") trends that have steadily deteriorated, where the upward sloped trend line in both graphs is indicates progressively poorer performance. Figure 1.10 below shows Rhode Island Energy Customers Experiencing Multiple Interruptions ("CEMI") performance as compared to the 2021 EEI Survey.

Figure 1.8: Rhode Island Energy Reliability (SAIFI) 2011 – 2021



Rhode Island Energy's System Average Frequency Index has been getting worse over the last ten years. As a result, customers have more outages than they experienced previously, on average.

Figure 1.9: Rhode Island Energy Reliability (SAIDI) 2011 – 2021



Rhode Island Energy's System Average Duration Index has been increasing over the last ten years, meaning that customers are experiencing longer duration outages on average than they saw previously.

Figure 1.10: Rhode Island Energy CEMI Performance VS EEI Survey 2021

Table 2. RIE CEMI n, IEEE calculation, Storms included.

Year	Cs	CEMI 3+	CEMI 4+	CEMI 5+	CEMI 6+	CEMI 7+
2019	496,961	19.81%	11.09%	5.63%	3.71%	2.25%
2020	498,157	24.67%	12.94%	6.74%	3.12%	1.66%
2021	499,886	20.63%	10.34%	4.55%	2.45%	1.09%
Averages	498,335	21.70%	11.46%	5.64%	3.09%	1.67%

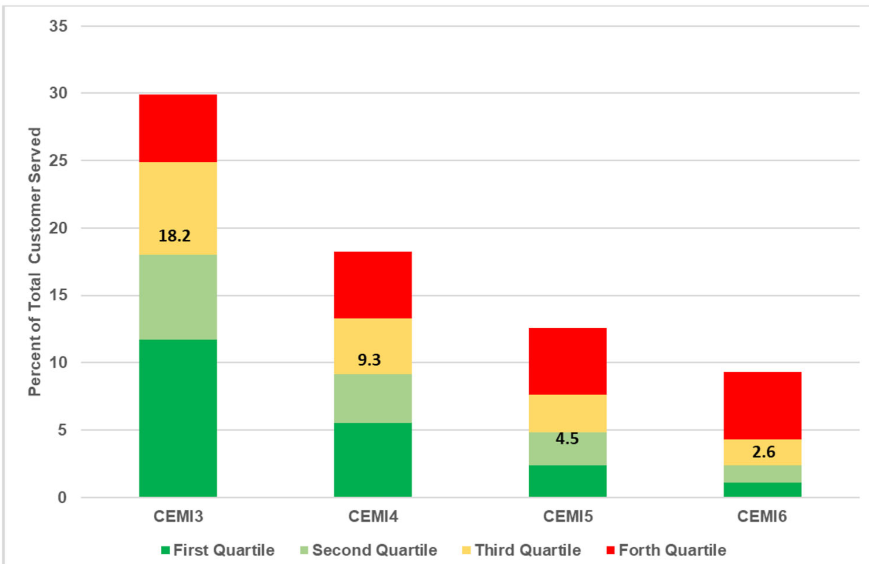


Figure 1.10 includes EEI survey information from utilities that benchmarked CEMI which is a reliability measure that tracks Customers Experiencing Multiple Interruptions, CEMI is a metric used to track pockets of customers whose reliability is poorer than average and may not improve while the overall system reliability is improving. Rhode Island Energy's CEMI performance is in the third quartile when compared to this EEI benchmarking.[32]

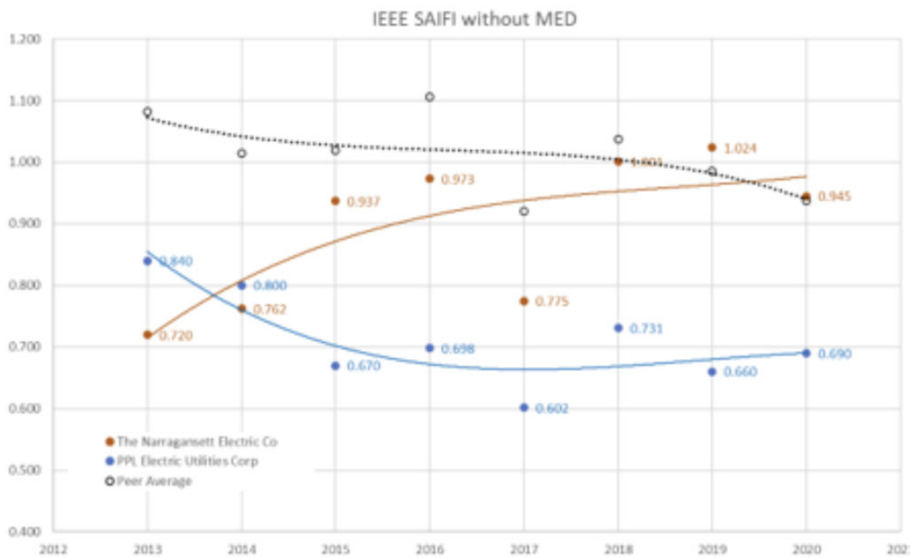
While Rhode Island Energy has been meeting its regulatory reliability performance targets as measured by SAIDI and SAIFI, to better understand Rhode Island Energy's relative reliability performance, the Company compared Rhode Island Energy's reliability trend to six peers of medium to large size utilities serving more than 300,000 customers in the United States and reporting 5-minute outages. The peers were in a similar geographic area of the United States to minimize the impact of weather differences.

[32] Customers Experiencing Multiple Interruptions (CEMI) is a reliability metric that places more weight on customer-centric metrics.

The analysis utilized EIA IEEE SAIFI data from 2013 – 2020.[33] The analysis compared Rhode Island Energy, PPL Electric Utilities in Pennsylvania and an average of the peer companies.

As can be seen in Figure 1.11, Rhode Island Energy lags in reliability performance when compared to its peers and to PPL Electric. From 2013 – 2016, peers have improved their SAIFI by more than 15%. PPL Electric improved SAIFI by 22% and Rhode Island Energy decreased their SAIFI performance by 5% over the same period. This relative performance continued from 2017 through 2020. Rhode Island Energy's performance is declining when compared to itself and its relative performance is also declining when compared to others over the same period. PPL Electric's performance gain is partially attributable to a system wide FLISR deployment that uses ADMS as part of the Company's GMP investment. It is likely that many of the utility peers have also implemented FLISR to enjoy reliability performance gains as well.

Figure 1.11: Rhode Island Electric Reliability Compared to PPL Electric and Peers



Reliability of the Rhode Island Energy distribution system has declined over the past several years as the system has aged and the penetration of DER has increased while the trend for PPL Electric and others has improved, largely due to investing in FLISR. FLISR, which includes the targeted deployment ADMS Basic and Advanced Reclosers that are included in the Foundational Investments is expected to improve Rhode Island Energy's reliability performance by reducing the frequency of outages that customers experience.

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[33] *See* https://www.eia.gov/electricity/annual/html/epa_11_01.html. Reliability data available at the time of the analysis extended through 2020 for Rhode Island Energy peer utilities.

Improving reliability is a key to improving customer satisfaction. One of the primary benefits of FLISR is that it will reduce the number of customers who experience a sustained outage. FLISR will also provide increased visibility into outage events occurring on the system for Rhode Island Energy's engineering and operations personnel, which will inform its operations and future investments in the system. Rhode Island Energy forecasts that SAIFI will improve by up to 30% with the GMP Foundational Investments. FLISR is also expected to improve Rhode Island Energy's CEMI performance (Figure 1.10), which is the metric of how many customers experience multiple interruptions. It will establish necessary grid modernization infrastructure to have better visibility, control, and optimization of the distribution system. The recommendation to accelerate certain Foundational Investments set forth in this GMP is supported by the availability of ADMS Basic, which results in early benefits that are closely timed with the installation of advanced field devices, coupled with PPL's grid modernization deployment experience over the last decade, which provides increased confidence in Rhode Island Energy's deployment plans.

SECTION 2: Current State of Today's Grid

This Section describes the status of grid modernization in the United States and how Rhode Island compares; defines the present DER interconnection trends and operational needs of the Rhode Island Energy system; describes operational limitations and challenges that are present today and are predicted to escalate in the future; and defines the limitation of the current system in enabling achievement of the State's Climate Mandates.

2.1 Grid Modernization in the United States

Across the United States and globally, the energy landscape is changing and according to the Department of Energy ("DOE"), today's electric grid lacks "the attributes necessary to meet the demands of the 21st century and beyond."[34] As technology advances and customers have greater opportunity to manage their energy needs through personalized load management and adoption of beneficial renewable DG, EVs, and EHPs, demands on the grid are becoming more dynamic and less predictable, as discussed in Section 1, above.

Grid modernization, then, refers to all efforts to bring the electric grid into alignment with current and future needs of the modern-day grid. While grid modernization has been used to encompass a broad array of initiatives, common themes include improving the grid's responsiveness, interactivity, and resilience.[35] There are many drivers for this, including emerging technologies, evolving consumer demands, cyber security concerns, extreme weather events, and a broadly shared desire to reduce greenhouse gas ("GHG") emissions by supporting the development of low-carbon energy infrastructure. Because it involves identifying and prioritizing a suite of near-term investments in new and emerging technologies to enable unprecedented capabilities in an uncertain future, grid modernization is among the most complex challenges that utilities, regulators, and stakeholders grapple with today. A discussion of the implications for DER penetration, drivers and a summary of notable recent grid modernization developments in other states is presented in Attachment B. This research suggests that many utilities and their regulators throughout the United States are recognizing the need for grid modernization and rapidly making investments. Many of Rhode Island Energy's peers have received approval and already have or are in the process of acting to systematically make grid modernization investments to transition to a reliable modern-day grid that is capable of meeting operating, customer and clean energy goals and realize savings because of these actions. When comparing grid modernization activity in 2021 to that occurring the five years prior across the United States, the 50 States of Grid Modernization Q4 2021

[34] United States Department of Energy, *Grid Modernization Initiative,* https://www.energy.gov/grid-modernization-initiative
[35] NC Clean Energy Technology Center, *50 States of Grid Modernization: Q1 2019 Quarterly Report Executive Summary* (May 2019), https://nccleantech.ncsu.edu/wp-content/uploads/2019/05/Q12019_gridmod_exec_final.pdf Schedule SL-1

Report [36] noted that the total grid modernization action increased by about 25% (in 2021) over the past year (2020), with states and utilities taking approximately 822 actions in 2021, compared to 658 actions in 2020, 612 actions in 2019, 460 actions in 2018, and 288 actions in 2017. In 2021, activity increased in every category tracked by this report, with greatest increases in financial incentives (39%) and deployment (35%). If investments are made according to this GMP proposal, it will provide the same opportunity for Rhode Island Energy electric customers as being afforded to customers in most of the other states that are already embracing grid modernization.

2.2 Rhode Island Energy's Electric Distribution System - Background

The existing Rhode Island Energy distribution system is designed and operated to maximize reliability in a safe, efficient, and affordable manner. The system is designed to accommodate customer electrical requirements with respect to how and when they demand power from the grid. Load utilization trends have been studied over many years to identify the extremes of peak usage. In the past, a system designed to handle voltage and loading concerns during the peak load periods would inherently be sufficient during off-peak periods. Specifically, the legacy distribution grid has been designed under the following paradigms:

Voltage[37]
- Voltage drop during peak periods is greater than voltage drop during off-peak periods.
- Voltage levels decrease from the source end of the feeder to the remote ends of the feeder.

Loading[38]
- Loading is highest during periods of peak consumption.
- Load levels decrease from the source end of the feeder to the remote ends of the feeder.

Fault Current[39]
- Fault current decreases from the source end of the feeder to the remote ends of the feeder.

Rhode Island Energy's legacy electric distribution system uses autonomously controlled devices resulting in little visibility of real-time system conditions for the distribution system operator. Some improvements and advancements in autonomous control have occurred over time and are continuing. Examples of autonomously controlled devices that are used on the Rhode Island Energy system are provided in Figure 2.1.

[36] NC Clean Energy Technology Center, *50 States of Grid Modernization: Q4 2021Quarterly Report & 2021 Annual Review Executive Summary* (Feb. 2022), https://nccleantech.ncsu.edu/wp-content/uploads/2022/02/Q42021-GridMod-Exec-Final.pdf
[37] Voltage is electric potential or potential difference expressed in volts.
[38] Load is the amount of power being consumed on the electric system at any given moment.
[39] Fault current is any abnormal electric current. An open-circuit fault occurs if a circuit is interrupted by some failure

Figure 2.1: Example of Autonomously Controlled Devices on Distribution Feeders

Category	Example Device	Prior Standard Control/Sensing	Current Standard Control/Sensing
Voltage	Switched Capacitor	Time Clock – No Sensing	Electromechanical Relay – On-Site Sensing (Amps/Volts)
Loading	Substation Ammeter	No Control – On-Site Sensing andMonitoring (i.e., Manual Reads requiring Crew Dispatch)	Analog Signal – On-site Sensingwith Remote Monitoring (EMS RTU)

In prior years, capacitors could be set using the historical load cycle with time clock controls. There was no on-site sensing for these installations, meaning these devices did not sense current or voltage. Common settings included switching the capacitor on at 10:00 AM as daily load was expected to increase and switching the capacitor off at 10:00 PM as the evening load was expected to drop. With current levels of DER penetration and two-way power flow conditions that are prevalent in a modern-day grid, dependence on a daily load cycle is no longer possible and the need for on-site sensing is increasing. In response, the Company has revised its standard capacitor control to an electromechanical relay that is activated based on current (i.e., amps) and voltage (i.e., volts) at its location and switches the capacitor on or off as necessary.

For loading information, the Company has relied on source-end substation ammeters. Through modeling, the source-end loading information has been allocated throughout a distribution feeder using the "peak planning" and "one-way flow" characteristics. In prior years, the substation ammeters were recorded by crews during regularly scheduled inspection efforts. Under the current Energy Management System ("EMS") construct, the ammeter data is passed through the substation's Remote Terminal Unit ("RTU") at various time intervals. Today,only 65% of the Company's distribution substations report interval information into the EMS. However, this is substation data only. Feeder data is not available to the EMS system.

System protection is another key requirement of any grid modernization plan. Fault or short circuit current is an extremely high level of amperes that flow from all generation sources into a short circuit (i.e., fault location) until the fault is cleared by a protective fuse, recloser or breaker. When fault current only comes from large, central generators connected to the transmission system, protective devices with on-site fault current sensing could be placed in series and set sequentially so that downstream devices operated first. Although the relays that sense the fault current have improved, offering an increased variety of settings, the fundamental sequential operation methodology has not changed.

Study tools, systems and data are needed for Rhode Island Energy's distribution planning engineers to properly plan for maintenance and operations and to perform system studies for future conditions. These tools currently include CYME Power Engineering software[40], Basic Outage Management System ("OMS"), Load Modeling, DMS power flow, OMS, Hidden Load, and Contingency Analysis. Dynamic analysis tools are needed and will be provided through the GMP Foundational Investments, to address voltage and stability issues that are present today and will increase with the rapid adoption of DER on the system and the retirement of spinning synchronous generation, which will elevate the need for stability analysis.

In summary, some improvements have been made and continue to be made in sensing and control of the distribution system; however, these improvements still only support autonomous one-way devices and source-end (i.e., substation) sensing is still used to predict remote-end performance. The Company currently replaces fixed and time-clock based switched capacitor banks on an opportunistic basis or as a part of an energy conservation program such as VVO/CVR; however, the current pace of deployment of such advanced capacitors and other advanced field devices is not fast enough to keep pace with the accumulation of DER loads now being experienced and the significant increase that will be required going forward to meet the State's Climate Mandates. Furthermore, as the complexity of the system increases, it is causing the need for more advanced tools that can perform dynamic system analysis, for example.

2.3 Current Grid Modernization Activities

As described in Section 1.2, the ASA approved in Docket No. 4770 included a limited set of grid modernization investments

The Foundational Investments proposed in this GMP build upon this initial work and consist of an integrated portfolio of solutions to be deployed through 2028. The initial grid modernization investments deployed under National Grid ownership are described below. PPL is continuing to advance these investments during the TSA.

- **System Data Portal**: The Company has delivered and continues to maintain the System Data Portal. The costs were incurred through Rate Year 3 to develop and maintain and support the system and to perform enhancements to the underlying infrastructure. There are no specific data portal enhancements identified at this time. The functionality is used frequently to facilitate DER interconnections.

- **GIS Data Enhancements**: The Company delivered upgrades and changes to the GIS platform to accommodate new asset types, equipment and data attributes (data model changes), and

[40] https://www.cyme.com/software/ and future described in Section 5

additional tools and enhanced features to manage data quality and improve processes in GIS. GIS data improvements and data hardening were also accomplished, which included general data cleanup as well as changes to baseline GIS to allow for new asset types, new equipment, expanded attributes, and characteristics. As part of the transition, PPL will migrate Rhode Island Energy's GIS into another platform that will be consistent with that used in PPL's other jurisdictions and where interfaces to ADMS have already been developed. The GIS is key to the Network Model [41]capability to support GMP[42]; however, the migration of it is not included in this scope because it is part of the Acquisition costs.

- **ADMS**: The Company completed an analysis and scoping effort for the development of the ADMS project. Business capabilities and system requirements were captured. Phase 1 ADMS system design activities were complete, vendor contracts were initiated, and system testing if the initial functionality was competed under National Grid ownership. Although Rhode Island Energy may use a PPL-aligned ADMS system, the ADMS basic training and ADMS related model / data work applies to ADMS Basic, so Rhode Island customers will receive benefits from such training.

- As discussed above, PPL is providing the ADMS Basic platform to Rhode Island Energy as part of the transition, the allocated costs of which will not be charged to Rhode Island customers. A discussion of how Rhode Island Energy will utilize ADMS going forward to integrate with other grid modernization functionalities is provided in Section 6 of this GMP, where it will be enhanced utilizing a phased approach where different modules and functionality will be incrementally added and placed into service over the next few years. This will maximize value and benefits realization as early as possible as well as help to align ADMS with critical dependencies such FLISR, VVO and TVR.

- **RTU Separation**: As part of the overall ADMS work stream, the Company also completed the RTU Separation work.

- **Underlying IT infrastructure**: The Company has completed an architecture assessment of the current integration tools in use, and their applicability for the GMP. In addition, the Enterprise Service Bus (ESB) platform was selected, requirement defined, and the design and development efforts were completed. Other efforts that advanced under the National Grid ownership includes the Data Lake, Advanced Analytics, and implementation of Cyber Security services. These

[41] Network Model is an IT platform that includes a topical representation of the power system and its connectivity, enabling power system analysis to make operating and planning decisions are based upon information that is available in real-time due to the exchange of information between systems, services and devices.

[42] The costs associated with migrating the existing GIS platform into a PPL platform are included in the Acquisition costs and will not be charged to Rhode Island customers; therefore, it is not included in the scope of this GMP.

activities will pivot to and be integrated with the PPL ecosystem of IT infrastructure as part of the transition.

- **Telecommunications**: Operational expenses will continue to be charged to Rhode Island Energy as rent expense as needed for the communication related to the ADMS system while the TSA is in effect. The Service Company's Telecom Operations and Management Solution ("TOMS") Phase I went into service December 2021. Certain communications networking and operation center have been designed but are not in service. These designs will be reviewed and continued or replaced by PPL during the TSA period.

- The Company initiated planning and scoping to engineer, design, manage, and deliver a network of devices and connectivity in collaboration with the preferred vendor for AMF under National Grid USA ownership which was informed by bandwidth requirements for the Data Lake and Advanced Analytics. Under PPL ownership, the RF Mesh communication network was proposed through the AMF filing made in November 2022. That coupled with cellular services and proposed fiber infrastructure will accommodate telecommunications needs for the GMP.

In addition to the initial grid modernization investments approved in the ASA, the Company has also deployed advanced field devices and VVO/CVR on select feeders over the last 3-5 years. The Company has deployed VVO/CVR capability through approved investments in feeder monitoring sensors, advanced capacitors and regulators, and a stand-alone VVO/CVR control platform through Company's VVO/CVR Pilot program funded through the electric ISR plan. To date, the Company has implemented VVO/CVR on 45 feeders from 11 substations in Rhode Island. Implementation of VVO/CVR has included the deployment of 61 feeder monitoring sensors, 170 advanced capacitors, and 61 advanced regulators. The Company has also deployed 574 advanced reclosers on over 235 feeders in Rhode Island as part of customer requests for DER interconnections (62 midline reclosers and 107 PCC reclosers)[43] and all other Company programs requiring new reclosers including for safety/reliability, damage/failure, and asset replacement (377 midline reclosers).

2.4 Rhode Island Energy DER Interconnections and Challenges

In Rhode Island, programs such as the Renewable Energy Growth ("REG") Program and evolving customer expectations due to the continual and rapid digitization of customer information have changed the one-way power system paradigm.[44] Customers can export electricity back to the grid and, if eligible,

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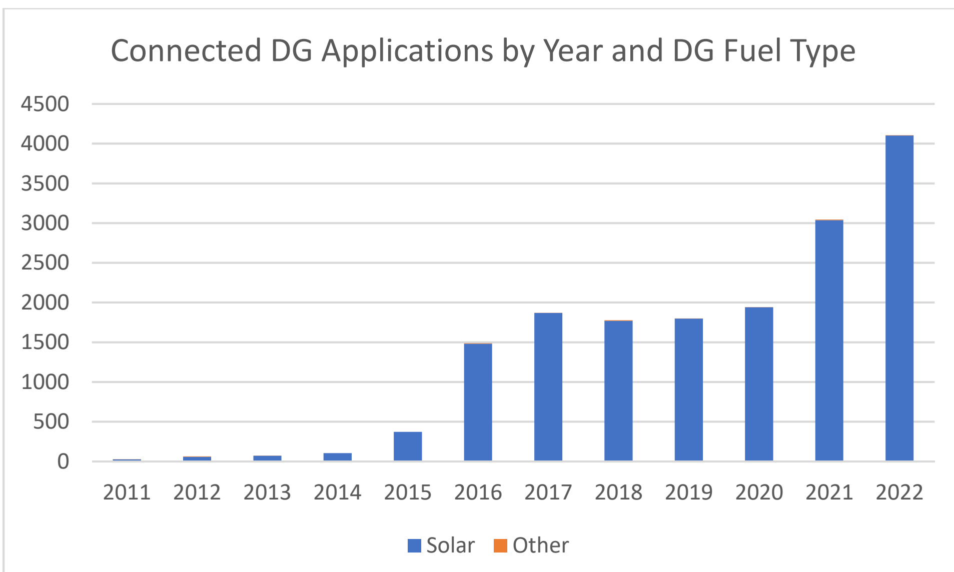
[43] Point of common coupling or "PCC" means the point where the generating facility's local electric power system connects to the utility's electric system.

[44] Digitization refers to investment and installation of additional grid sensors and two-way communicating devices, including smart meters, requires a substantial investment in underlying telecommunications, operational data management, system performance modeling and evaluation tools, and both underlying physical and cyber security. As such, a core component of

participate in net energy metering ("NEM") or REG programs. Many customers are beginning to expect their "smart appliances" or "smart homes" to be able to communicate with the utility so they can better manage their energy use.

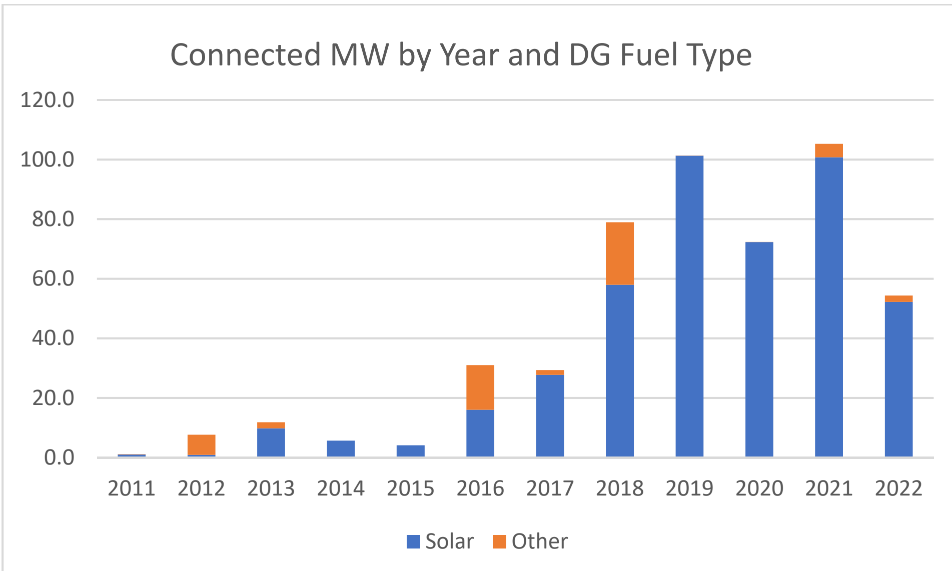
The Company is seeing dramatic increases in renewable DG applications, particularly solar DG. Figures 2.2 and 2.3 show the increasing trends in the number of renewable DG applications and megawatts ("MW") of capacity interconnected in Rhode Island over the past twelve years. For the 5-year period from 2017 through 2021, the Company interconnected over 387 MW of DG, which was a 327 MW increase or more than 5 times greater than the 5-year period from 2012 - 2016. As such, a core component of grid modernization is the management of and interaction with an increasing volume and diversity of data – illustrating the vital importance in how we gather, transmit, and store data within and across systems.

Figure 2.2: New DG Applications Interconnected Through December 2022



the modern distribution grid is the management of and interaction with an increasing volume and diversity of data – illustrating the vital importance in how we gather, transmit, and store data within and across our systems.

Figure 2.3: New DG Nameplate Capacity Interconnected Through December 2022



The Company currently has about 671 MW of DG projects in queue (i.e., "pending"), with 25% at the initial stages of the interconnection application process and 75% in the final stages.[45] The Inflation Reduction Act ("IRA") in August 2022 will be a growth catalyst for the solar industry nationwide where solar deployment is expected to increase by 62 GWdc, or 40%, over the next five years (2023 – 2027)[46]. Based on the Company's recent interconnection rates, there may be an additional 120-250 MW interconnected within the next 3-5 years. The uptick has been attributed in part to an expansion of the Public Entity definition for remote net metering in Rhode Island. A continuation of renewable and DG incentive programs in Rhode Island coupled with the existing impact of the IRA are expected to continue to drive application volumes for at least the next 3-5 years.

The Company continues to see added MW from larger "complex" applications as third-party developers attempt to realize greater economies of scale and pursue Rhode Island's Community Solar incentive programs. Since 2020, 19 developers have added 103 name plate MW capacity. This equates to 44% of all added MW capacity during this time-period.

Over the last few years, Rhode Island has seen a large increase in the number of applications for solar DG, low but increasing levels of EV and EHP adoption, and broader participation and interest in opportunities to lower electric bills and/or take advantage of new revenue streams. However, some of

[45] Final stages of the interconnection application include those in Conditional Approval, Design, Construction, and Meter Installation stages.
[46] Wood Mackenzie, September US Solar Market Insight Executive Summary, Q3 2022

the challenges associated with interconnecting DER are increasing. Receiving local permitting approval, getting proper financing in place, and high site costs (including utility system upgrades to interconnect) are all risks associated with DER projects. Currently, due to these and other issues, on average since 2011, more than 55% of DG applications are cancelled prior to completing the project. The high saturation of current and proposed DER being seen in Rhode Island today, and the need for additional distribution capacity to accommodate these higher levels of DER proposals, has prompted transmission level studies under the ISO-NE requirements which add time, and, in many cases, costs to this process.

Exacerbating many of these issues is the fact that the electric systems serving the areas with the most potential for DG development in Rhode Island are areas designed to serve small amounts of load for one-way power flow. The Company is seeing a high level of DG aggregation in rural areas where there is available land, but the electrical systems in these rural areas often do not have the available hosting capacity and are not robust enough to interconnect larger DG sites that introduce multi-directional power flow. Issues resulting from DER interconnections in these areas often include voltage, power quality, and protection coordination. System modifications including substation modifications, line reconductoring, advanced control and monitoring, and advanced protection schemes are required to maintain compliance obligations. These modification investments can be in the multi-millions of dollars and take in excess of 12 – 24 months to execute.

As a result of the increasing demand for DG interconnections, the existing hosting capacity on many feeders in Rhode Island has decreased dramatically. Figure 2.4 shows the level of DG that would be able to be interconnected on all 3-phase feeders in Rhode Island without requiring significant distribution system upgrades in November 2022.[47] This compares with Figure 2.5 showing the level of DG that could have been connected in 2019. This hosting capacity map was generated using the Rhode Island System Data portal and includes only the currently interconnected DG in the state. As can be seen, many feeders that had hosting capacity three years ago have now turned red, meaning that there is less than 300 kW of hosting capacity left. The situation is much worse when the pending DG applications are included.

[47] Three-phase feeders are all feeders with 3 wires to accommodate 3-phase power. 3-phase feeders are typically mainline feeders but can also include side taps (past fuses), which would typically not be mainline.

Figure 2.4: Rhode Island System Data Portal Hosting Capacity Map – November 2022

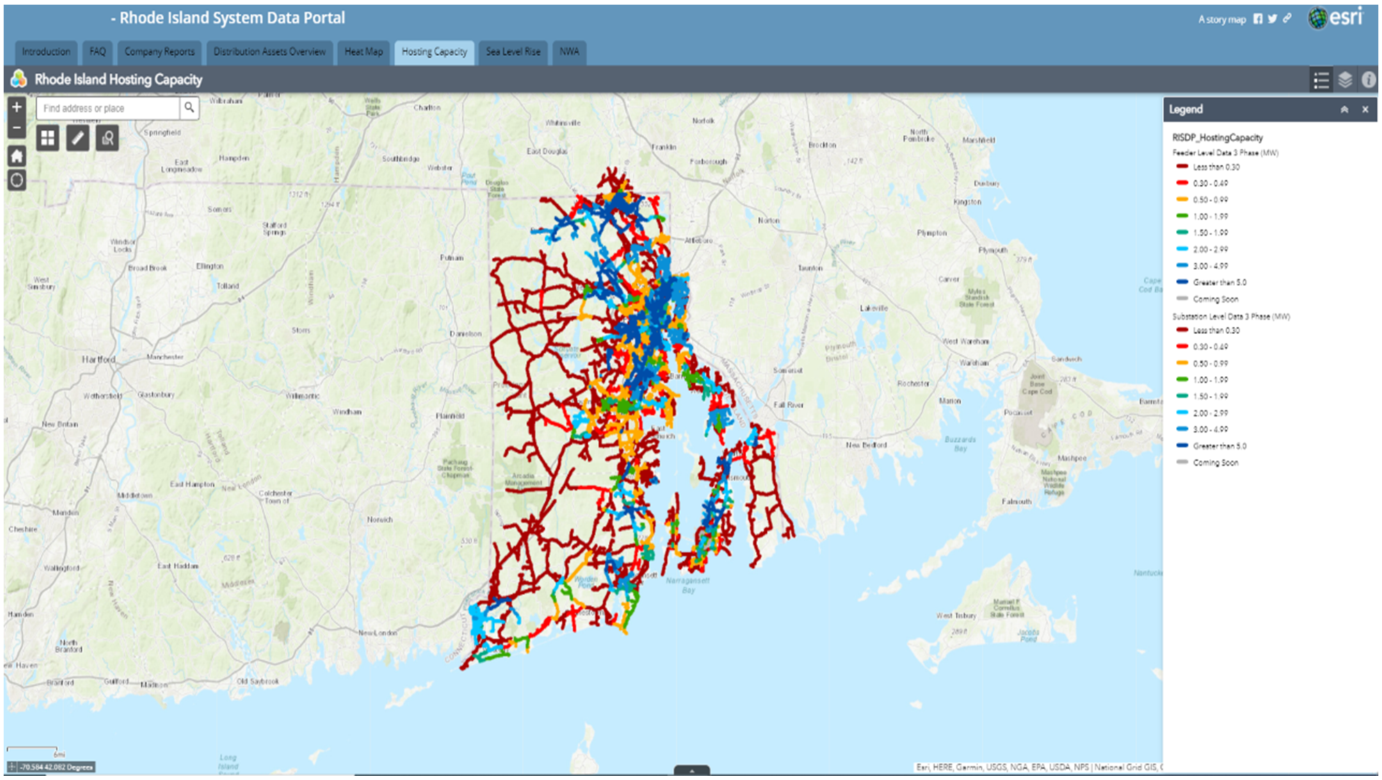
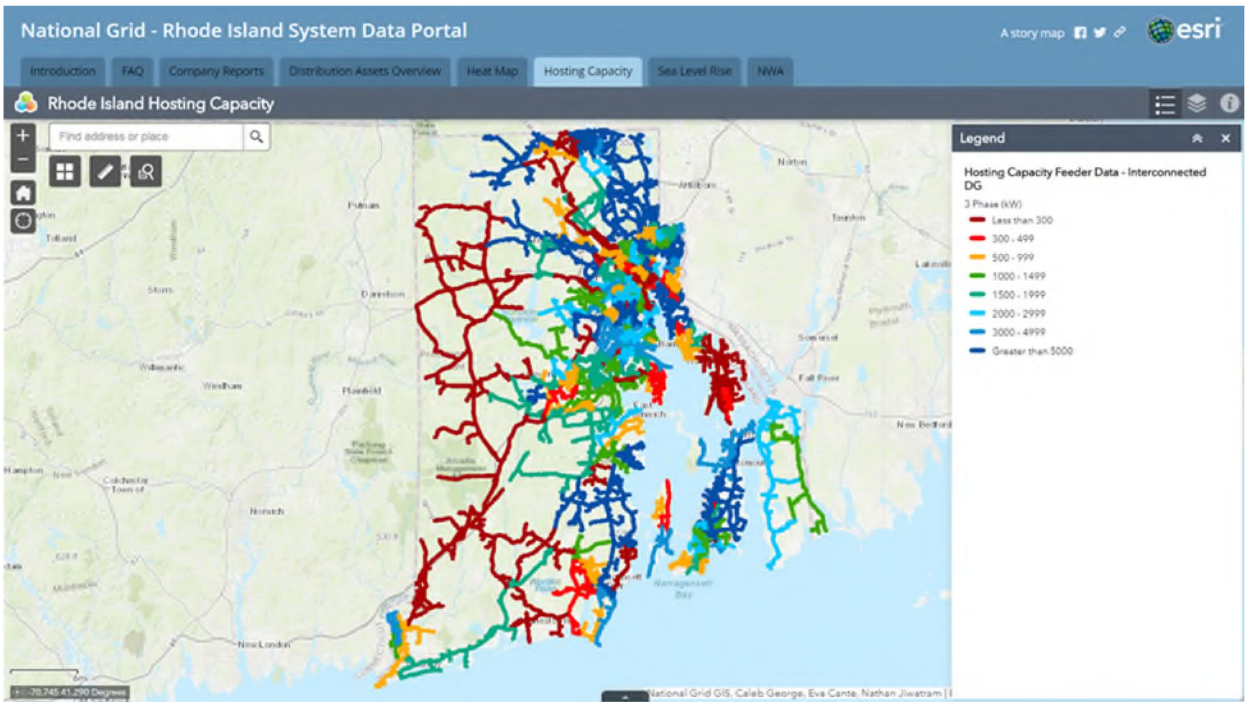
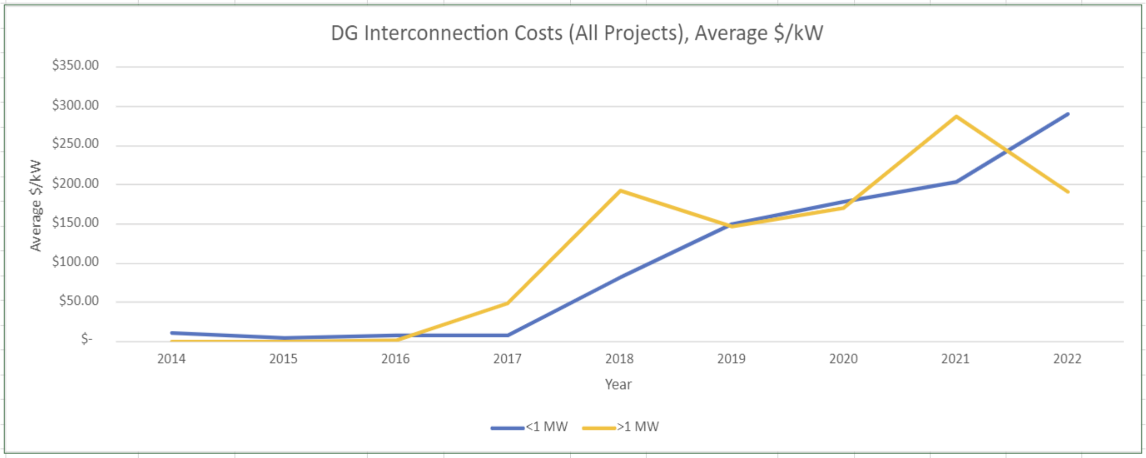


Figure 2.5: Rhode Island System Data Portal Hosting Capacity Map – 2019



The lack of hosting capacity throughout much of Rhode Island means that costly system upgrades will be necessary for interconnecting most new DG projects. As a result, interconnection costs have increased dramatically over the last few years for both smaller-scale and large-scale DG projects. Figure 2.6 summarizes the interconnection costs tracked by the Company for proposed DG projects in the last six and a half years. As can be seen, interconnection costs have recently increased significantly since 2017. DG interconnection costs in Rhode Island are expected to rise even more substantially in the future due to DG saturation.

Figure 2.6: DG Interconnection Cost Trends



2.5 Operational Needs

This section of the GMP summarizes the operational issues and needs of Rhode Island Energy's electric distribution system. It also describes the operating limitations that are present today without having grid modernization tools. In addition to declining reliability, which was described in Section 1.9, this section describes the implications of operating a modern-day grid without the visibility, control and protection that is needed and would be available with GMP. Recovery efforts from the August 2022 event at the Nasonville substation are described along with the benefits and cost savings that would have been available if GMP investments had already been made. This section also discusses a variety of operational needs such as improving resiliency, saving time and money recovering from storms, overcome interconnection limitations, and prepare for the implications of FERC Order No. 2222, which opens up market opportunities for aggregators.

- **Rhode Island Energy Distribution System Issues Today**

  Customers are already interconnecting renewable DG, driving EVs, and participating in demand response ("DR") programs at increasing rates. This trend will continue and will likely escalate as customers' expectations and technologies evolve. As customers adopt more DER, the distribution system is becoming more dynamic and complex. Each new DER interconnection has a physical impact on the grid and creates new challenges and opportunities for distribution system planning and operations. In Rhode Island, distribution operating issues are already beginning to emerge, and these issues will become more systematic as more DER and beneficial electrification are adopted. Reliability and safety impacts may result from these DER-caused distribution system issues:

– Overloading of conductor, line equipment, station regulators, and supply transformers
– Increase of overvoltage during minimum load conditions due to DG and in some cases low voltage during peak conditions
– Power quality and voltage fluctuation concerns in rural areas with less robust electric systems
– Ground fault overvoltage concerns
– Islanding concerns with mix of rotating and inverter-based generation with different islanding algorithms
– Protection coordination concerns, specifically desensitization of ground fault protection
– Exceeding equipment short circuit ratings

These issues are already causing the Company to develop and recommend system upgrades to accommodate new DER projects, which in some cases, result in DER project size reductions or project cancellations due to the high costs to customers and third-party developers.

Specific examples of system issues and DER project impacts, where the construction cost and timeline to integrate a DER resulted in negative economic impacts or significant project size decrease, are summarized in Attachment D.

- **Operating Limitations**

There are many operating limitations that presently exist on Rhode Island Energy's modern-day grid today, such as those listed below:
  – Lack of visibility and situational awareness of actual system conditions.
  – Inability to identify and control daily voltage variations within required tolerances.
  – Inability to identify thermal overloads and remotely take corrective action.
  – Inability to remotely monitor, manage, and control DER.
  – Inability to balance load and generation.

Most of these operational limitations are present at times on some areas of Rhode Island Energy's electric distribution system today and will only be exacerbated as more DER interconnections occur. Practical examples of the operating limitations are provided below along with a discussion of how GMP investments can overcome them. These examples demonstrate how GMP investments will provide direct benefits for Rhode Island Energy, its customers and the enablement of Rhode Island Climate Mandates.

- **Lack of Visibility and Situational Awareness**

Rhode Island Energy generally does not have visibility or situational awareness of the distribution system today and is already experiencing back flow on feeders and voltage excursions on the system for the DER that have been interconnected. Given the increase in roof top solar photovoltaic ("PV"), safety concerns are emerging with line-down conditions for the utility crews and the public. Unfortunately, most of the operational issues are being uncovered after they have arisen because of the lack of system information available at the control center. As revealed in Figure 2.4, many of the distribution feeders in Western Rhode Island, are reaching the limits of their hosting capacity which is restricting additional DER interconnections without overloading the circuit. Currently, few distribution feeders are remotely monitored or controlled, so there is unrecognized backflow, over and under voltages, thermal overloads, and hidden load, which can cause reliability, safety and incorrect operating actions from the lack of system visibility.

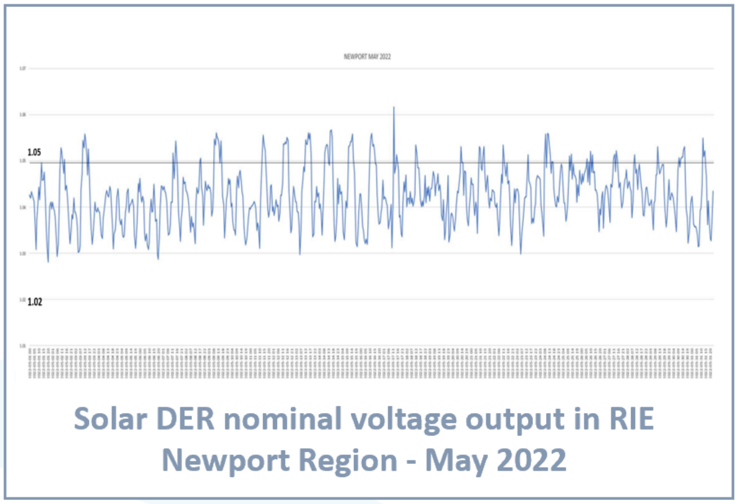
GMP, especially coupled with granular data inputs from AMF,[48] will provide visibility and situational awareness by bringing together multiple streams of important data from advanced field devices and AMF. That data is synthesized in a cogent way to provide real-time, relevant information in a single location to bring necessary system visibility to distribution system operators.

- **Inability to identify and control daily voltage variations within required tolerances**

  DER are impacting the Rhode Island Energy distribution networks because they introduce new voltage variability characteristics that are dynamic and increasingly uncertain. Rhode Island Energy is required maintain ±5% of nominal voltage i.e. 0.95 to 1.05 per unit voltage per American National Standard Institute. Rhode Island Energy is currently experiencing voltage excursions on distribution feeders as a result of unmonitored and uncontrolled commercial-sized (approximately 5 MW) solar PV installations (see Figure 2.7).

[48] AMF refers to the functionality provided by advanced meters, also referred to as smart meters. The Company filed to deploy full-scale AMF in November 2022 which, if approved, will replace the presently used automated meter reading ("AMR") systems solution in Rhode Island that collects billing information with a "drive-by" technology. AMF is a broader concept than Advanced Metering Infrastructure ("AMI"); AMI commonly refers only to the smart meters themselves. AMF, used universally throughout this filing, refers to the functionality that comes from the broader deployment of hardware and software solutions needed to utilize the smart meter data in a timely and efficient manner.

Figure 2.7: Example of a Voltage Deviation at Rhode Island Energy



During high solar production during the mid-day of many non-peak months, high voltage limits are being exceeded later in the day and during the summer months with high air conditioning demand, low voltage limits are being exceeded. When voltage limits are exceeded, flash overvoltages can occur which often will damage equipment and cause service interruption. When voltage falls below the lower voltage design limit, induction motors stall and current increases, and customer's equipment can be damaged. Low voltage often causes costly failures at customer locations. Low voltage events interrupt sensitive processes, shorten the useful life of equipment (over heated motors, etc.), and cause computer and communications failures.

For the most part, Rhode Island Energy becomes aware of voltage issues when customers complain because the Company generally does not have the ability to monitor voltage violations remotely without special equipment. Furthermore, much of the voltage regulating equipment is not equipped to manage this daily volatility of power flow conditions on the distribution feeders that are caused by DER interconnections[49]. GMP offers the voltage sensing data, the communications infrastructure, and the advanced capacitor and regulator controls and ADMS: when operated with inputs from the AMF granular voltage data, voltage can be monitored and managed within operating limits and optimized to result in energy efficiency.

[49] Many capacitor banks operate in the fixed mode and are "on" all the time which can aggravate the high voltage periods. Taking them off-line requires dispatching crews to each location and that is not practical because the devices need to be "on" during the low voltage hours of the same day.

- **Inability to identify thermal overloads and remotely take corrective action**

  Thermal overloads can occur with DER when switching occurs and the hidden load masks the anticipated current that a particular conductor is expected to carry resulting in a thermal overload. Hidden load, or masked load, is load offset by DER that an operator cannot see. Hidden load can quickly appear as load on the system and can be unanticipated without tools provided by GMP. As a result, operating decisions taken without the knowledge of hidden load can negatively impact safety and reliability.

  An example of this operating risk is highlighted by what occurred at Old Dominion in the spring of 2020[50]. Just after a normal afternoon ramp down of DER solar generation at approximately 6 PM, *Real Time* contingency analysis tools identified a post contingency thermal overload, resulting in an Emergency Rating on a 115-kV Transmission Line being exceeded. The contingency event studied the loss of another 115-kV Transmission Line in the area, but the post contingency overload was not identified in the *Day Ahead* contingency analysis. The reason that it was not identified was that the solar generation in question that was on-line at the time that the *Next Day* study was performed *masked the gross load* that was being served by the 115-kV Transmission Line which created "hidden load". During this event, the distribution system operators identified and performed a real-time switching solution to mitigate the post-contingency overload. Had a switching solution not been available, load curtailment would have been performed. This event highlights the importance of knowing the physical location of distributed generation, the real-time and forecasted total gross load, and the total gross generation at the transmission bus, or on the distribution system in Rhode Island Energy's case. Additionally, an understanding of net load is not sufficient, and DER cannot simply be treated as a "load reducer."

  If real-time monitoring of DER were available from GMP, it would have provided the visibility needed to operate reliably and safely because real time gross load and generation would have been available. Without specific real-time information that comes from monitoring DER and granular AMF data, the load can be masked causing operational actions that can have unintended consequences. As evidenced by the Nasonville event in September 2022, without GMP, Rhode Island Energy does not have the visibility needed to have situational awareness of these types of dynamic operating conditions that is needed to operate the complexity of the modern-day grid that is present in Rhode Island. GMP functionality will provide Rhode Island Energy with the necessary visibility and information to operate an increasingly complex and dynamic electric distribution system.

[50] Pennsylvania Public Utilities Commission Docket No. P-2019-3010128 Testimony #2 at 12 (December 11, 2019).

- **Inability to remotely monitor, manage, and control DER that are causing operational issues**

  Except for large interconnections that have a dedicated recloser at the point of interconnect, Rhode Island Energy currently has no awareness of real-time operating conditions of any particular DER. To the extent that a particular DER is causing problems on the system, it can affect other customers and equipment that are being served in the area. With GMP, Rhode Island Energy would have the ability to remotely detect problems, change settings and ramp down production to optimize distribution system utilization while maintaining a level of output from the DG that the system can reliably and safely accommodate.

- **Inability to properly protect distribution system components under the changing topology of the system – two-way flow, changes in fault current levels, obsolete relays, etc.**

  Electrical equipment that has the function of supplying energy to customers has a limitation with respect to the current that can flow through the equipment without overheating and damaging the equipment – lines, transformers, circuit breakers, wave traps, etc. Protective relays are in place to open or isolate this equipment when this occurs to protect equipment and for safety purposes. Due to the traditional radial nature of distribution systems, most distribution protective devices are nondirectional in nature, responding to a given value of current without regard to the direction that the current is flowing. Because DER produces fault current of various magnitudes for faults and the traditional radial nature of the distribution system is disrupted by multi-directional power flow from DER, relays can operate improperly. GMP includes functionality that will address this operating limitation to provide necessary protection as the distribution system becomes increasingly complex.

- **Operational Implications**

  Operating a modern-day grid without grid modernization functionalities introduces a series of risks for the Company, customers, and the State, such as:
  - Deteriorating safety and reliability – inability to isolate faults, automatically sectionalize and minimize customer outages, as described in Section 1.9.
  - Higher than necessary O&M costs due to lack of automation, and other services that GMP would provide.
  - Lengthy recovery time from storm outages.
  - Interconnection limitations can be inconvenient, costly and cause delays.
  - DER curtailment restricts contributions to the Climate Mandates.
  - Delays and challenges to recover from major events such as Nasonville.

The Nasonville event, described below, highlights the operational limitations that are present today and the implications of operating an increasingly complex and dynamic modern-day system without grid modernization.

- **Operational Implications: The Nasonville Story - Challenges to Recover from a Major Event**

On Tuesday August 23, 2022, at 18:23 the Nasonville Substation # 127 Transformer tripped off by transformer differential relaying. Operations of the equipment at the Nasonville Substation resulted in loss of all Nasonville Substation feeders and triggered alarms to Rhode Island Energy Distribution Dispatch in Lincoln, Rhode Island. A Rhode Island Energy Substation Supervisor arrived at the station shortly thereafter. There was fire burning inside the station switchgear with thick smoke. The Rhode Island Energy Overhead Line Department isolated the feeders from the switchgear. After confirming the isolation, the firefighters were allowed to enter the switchgear and put out the smoldering fire with portable chemical fire extinguishers. During this time additional Rhode Island Energy Engineering and Operations personnel responded to the station. Customers were picked up on feeder ties.

The event occurred from Tuesday August 23, 2022, at 18:23 to Saturday, August 27, 2022, at 19:00 with the decommissioning of "roll on" generation occurring on Wednesday, September 1, 2022. The following list describes the issues, how the GMP investments could have mitigated the issues, and approximate quantification of the benefits. The system conditions discussed below occurred in the process of restoring Nasonville:

1. Voltage Management:
    a. Voltage Issue 1 - Voltage dropped below American National Standards Institute ("ANSI") limits due to extended feeder length under outage reconfiguration. Approximately half of the devices had remote monitoring to provide visibility into low voltage issues, but the other half did not. Outside the Control Center's voltage visibility, some customers reported voltage as low as 96V at their houses, which is well below the ANSI requirement.
    b. Voltage Issue 2 - A Woonsocket Load Tap Changer ("LTC") set point adjustment was needed to compensate for the higher voltage drop resulting in lower remote end voltage due to additional loading and extended feeder length. A crew was dispatched to manually change the LTC set point.
    c. Voltage Issue 3 – The system had high voltage while trying to get the first mobile generator to come online. The high voltage prevented the generator operations from relieving load for approximately 2 hours. Remote tripping of capacitors were used to reduce voltage, but further voltage reduction was required. A crew was dispatched to adjust an upstream non-advanced regulator. Manual tap position adjustment of the

generator's step-up transformer and generator control power factor adjustment were ultimately necessary to bring the voltage within an acceptable range to bring the unit online.

   d. Voltage Issue 4 - A non-advanced regulator controller had a controller failure during the event resulting in high voltage. Crews were dispatched to troubleshoot the controller.

2. Loadflow Analysis:
   a. Loadflow Issue - Modeling the reconfigured system to perform load flow simulations that assessed potential contingency actions was necessary to support operations. It was difficult to perform these assessments with offline simulation tools due to repeated manual entry of multiple meter data points that was required to make offline model sufficiently accurate to aid contingency planning.
3. DER Dispatch:
   a. DER Dispatch Issue 1 - Pascoag Municipal's battery dispatch was done through phone calls between RIE's Control Center and Pascoag Municipal personnel. The daily dispatch was setup each morning. Although the initial daily battery dispatch setup was reasonable, cloud coverage of large PV sites on the 26W1 feeder combined with the battery charging schedule sometimes exacerbated loading issues. Operations needed to quickly adjust and readjust through phone calls with Pascoag Municipal personnel to change the battery status.
   b. DER Dispatch Issue 2 – PV generation sites tripped because of large voltage deviations, which resulted in excessive feeder loading.
4. Load Management:
   a. Loading Issue 1 – Crews had to be dispatched to switch locations for initial restoration and to restore the system to normal configuration.
   b. Loading Issue 2 - A large customer was asked to curtail their operations during the event to avoid system overloads. The customer shutdown their operations for approximately two days.
   c. Loading Issue 3 – Because the system was near its loading limits, load shed plans were developed. Customer communications were distributed for potential evening load shed needs during the immediate days following the station event. Although no load shed actions were taken, the proposed actions were developed using existing switch and protective device locations.
5. The operational benefits that would have been available with GMP include:
   a. Voltage Visibility GMP Benefit – More granular voltage visibility along the feeder would have allowed operations to respond to more voltage issues before customer complaints or equipment damage occur. This would be accomplished with an ADMS system, communication system, advanced capacitors and regulators, and real-time loadflow.
   b. Distribution Voltage Operational GMP Benefit 1 - Remote switching of capacitors and regulators would solve voltage issues and DER dispatch issues without dispatch of line

crews. This would be accomplished with an ADMS system, communication system, advanced capacitors and regulators, and real-time loadflow.

c. Distribution Voltage Operational GMP Benefit 2 - Remote control of capacitors and regulators would inform the Control Center of equipment or control issues before those equipment issues become critical. This would be accomplished with an ADMS system, communication system, and advanced capacitors and regulators.
d. Substation Voltage Operational GMP Benefit - Remote adjustment of LTC controls could have saved the crew dispatch to adjust the LTC manually. This would be accomplished with an ADMS system, communication system, and sensing from advanced capacitors and meters.
e. Real-Time Load Flow GMP Benefits - Real-time load flow tools would have merged real-time system configuration and meter data into the model automatically for fast simulations to evaluate potential contingency actions. This would be accomplished with an ADMS system, communication system, sensing from capacitors, meters, and reclosers, and real-time load flow.
f. DER Dispatch GMP Benefit 1 - Direct control of battery storage would allow for a faster coordinated response to provide optimal feeder load management during significant loading or generation changes. This would be accomplished with an ADMS system, communication system, sensing from capacitors, meters, and reclosers, real-time load flow, and a DER monitor/manage system.
g. DER Dispatch GMP Benefit 2 - DER Monitor/Manage would enable volt/var inverter controls that regulates voltage locally at PV sites to prevent tripping and prevent voltage swings should nearby sites trip or cloud cover occur. This would be accomplished with an ADMS system, communication system, sensing from capacitors, meters, and reclosers, real-time loadflow, and a DER monitor/manage system.
h. Load Management GMP Benefit 1 – Advanced reclosers would provide system self-healing and quicken restoration. This would be accomplished with an ADMS system, communication system, advanced reclosers, sensing from capacitors, and meters, and real-time loadflow.
i. Load Management GMP Benefit 2 – With the monitoring, load flow, and voltage control benefits of GMP, the large customer’s load could have been managed to avoid shutdown. This would be accomplished with an ADMS system, communication system, sensing from capacitors, reclosers, and meters, and real-time loadflow.
j. Load Management GMP Benefit 3 – Load shed plan could be developed at a much more granular level, potentially to the individual meter. This would be accomplished with an ADMS system, communication system, sensing from capacitors, reclosers, and meters, and real-time loadflow.

- **Operational Implications: Higher than Necessary O&M Costs**

  Grid modernization functionality that includes real-time load flow modeling and field automation is becoming an essential tool that is used to identify reliability issues before they occur and then take appropriate operating actions. It is becoming critically important to reliability and safety with the increased penetration of DER due to their variability resulting in huge load and voltage swings on the distribution feeders daily. Today, crews must be dispatched when customers report outages, and the extent and specific location of the outage is not known. When load is transferred to adjacent circuits, crews are dispatched to perform manual switching. Settings changes for relays and voltage regulating equipment must be done manually, which requires costly site visits and is typically performed on a seasonal basis. With the advent of two-way power flow and daily high and low voltage swings that are common with the modern-day grid, settings need to be changed more often. Having a real-time load flow model is an operational necessity.

  O&M savings can be achieved through reduced truck rolls from automated switching, remote settings and efficiencies associated with pinpointed dispatching. Nasonville can be used as an example where it would have resulted in the following savings: 1) approximately 2 crews dispatched for 5 hours for switching would have been avoided at the beginning and end of the system reconfiguration duration; 2) for the failed regulator control, approximately 5 troubleshooting crew dispatches would have been avoided including crew, operator, and engineering time; 3) the Company and customers would have saved from self-healing FLISR to avoid outages, pin-pointed dispatching and faster restoration; 4) with Real-Time Loadflow, it would have saved the Company 2 engineers approximately 3 days of analysis, 5) the Company could have possibly avoided paying a customer to curtail; and 5) GMP investments would have provided Control Center efficiencies from reduced time for switching order development and execution, operator time savings associated with access to real-time load flow, and faster decision making with access to granular system data.[51]

- **Operational Limitation: Storm Recovery/Resiliency**

  Rhode Island is subject to coastal storms and major weather events during all seasons of the year, which requires resiliency and having the ability to bounce back, recover quickly and get the system back to normal after being strained. Without having visibility and situational awareness of the system and little automation, it is very time consuming to locate, assess and restore service to customers.

[51] *See* Company's Response to Data Request Division 1-33, FY 2024 Electric Infrastructure, Safety and Reliability Plan, Docket No. 22-53-EL.3

With grid modernization, as the storms are encountered, AMF meter information coupled with grid modernization capability will provide operators with up-to-date system status to dispatch crews and take appropriate operating actions. Advanced reclosers will isolate damaged line segments and transfer load to undamaged feeders. Mobile dispatch will enable the most efficient dispatching to the pinpointed location in need of restoration. DER Monitor/Manage will dispatch DER on or off and/or up or down as required given local safety and generation needs. As recovery steps are taken and segments are restored, equipment settings can be remotely adjusted. As a result, service restoration of will be much faster and less costly, customer outage time will be reduced and the overall cost to recover will be less.

Grid modernization, with its self-healing attributes and real-time sensing to enable predictive equipment analytics and diagnostics, will add intelligence and resiliency to Rhode Island Energy's electric distribution system to better respond to major events. As highlighted in the following two case studies, GMP Foundational Investments bring essential functionality for resiliency of a modern-day grid that save cost and time for recovery.

Florida Power & Light ("FPL"): FPL achieved the company's best-ever service restoration time in response to Hurricane Ian in September 2022[52] by using grid modernization investments that made the grid smarter, stronger and more storm resilient. More than 40,000 smart devices collect and report data back into a state-of-the-art control center. The devices talk to each other to determine where there is a fault, allowing FPL to send the right resource at the right time to the right location. Prior to having the FLISR technology, crews had to drive around to look physically at the entirety of the power lines to determine where the fault was which would have taken days to restore power. Now, restoration can occur in a matter of hours (after a storm like Hurricane Ian) with smart grid technology that tracks outages and self-restores. Every address is located on screens in the control center that provides feedback to operators so they know when and where the power is out as soon as the lights flicker.[53] FLISR was a significant contributor to FPLs record recovery to restore power following Hurricane Ian, which was one of the most powerful storms to hit the US that caused widespread damage and flooding in Florida starting on September 28, 2002 when it made landfall.

EPB Chattanooga: EPB Chattanooga (EPB), deployed a grid modernization FLISR system to reduce the impact of power outages, which were historically estimated to have cost the community $100 million a year. On July 5, 2012, a severe storm/tornado came through the Chattanooga, causing widespread power outages that were restored with FLISR. EPB, realized a

[52] Utility Dive, *NextEra says FPL's speedy Hurricane Ian recovery could cost customers $1.1B* (Oct. 31, 2022), https://www.utilitydive.com/news/nextera-says-fpls-speedy-hurricane-ian-recovery-could-cost-customers-11b/635287/
[53] Linnie Supall, *FPL says new technology should help restore power sooner ahead of Hurricane Ian*, WPTV West Palm Beach (Sept. 26, 2022), https://www.wptv.com/news/state/fpl-says-new-technology-should-help-restore-power-sooner-ahead-of-hurricane-ian

55% reduction in the duration of outages experienced by their customers because about 90% of its fault detection and sectionalizing devices were programmed for automatic power restoration. EPB estimated that they were able to restore power to all customers nearly 1.5 days earlier than would have been possible before implementing their FLISR system, saving roughly $1.4 million in restoration costs.

As these case studies reveal, grid modernization deployment that is enhanced with granular AMF data, will provide significant resiliency for Rhode Island Energy to quickly recover from storms and major events when they do occur. These cost and benefits are included in the BCA in Section 8.

- **DER Curtailment and Interconnection Limitations**

Without having the required visibility and situational awareness in real-time operations, the Company uses the DER Interconnection Process as a method to protect system reliability. Without operational knowledge, system planners use conservative assumptions during the DER interconnection application phase. This often results in interconnection costs that may be higher than it would be if more granular information was available. As discussed earlier and in Attachment D, many DER projects are not pursued in Rhode Island because of these issues, making it more difficult to meet the Climate Mandates.

Without adequate visibility, distribution system operators also use conservative assumptions during operations, which reduces DER performance. As DER saturation continues to increase, the level of DER curtailment will increase until AMF and GMP functionality is deployed. Studies show that by 2030 DER curtailment will become very significant and necessary to provide reliable service

Rhode Island Energy engineers analyze the impact of DER on the distribution system's performance at the commencement of discrete System Impact Study ("SIS") agreements. The analyses conducted identify potential concerns due to specific DER interconnections and system modifications required to maintain compliance. Studies consider all interconnected and proposed DER within the analysis to determine if system modifications are needed to maintain reliability and safety. Modifications range from significant infrastructure upgrades to reducing the allowable size of DER interconnection. Approvals can take time and become expensive if system updates are needed which are stressful for the applicants.

Without the needed visibility, situational awareness, and control of the distribution system that AMF and grid modernization functionality and equipment provide, Rhode Island Energy's only method of controlling the operational issues defined above (voltage violations, thermal overloads, back flow, relay and protection, etc.) is to perform interconnection studies to identify potential issues. If system constraints and violations are identified with the added DER, then the developer must fund system upgrades to connect. However, this process is based on steady state load flow analysis and cannot capture the dynamic fluctuations on the system that occur within the day. As a result, it is possible that –unanticipated operational issues may result from DER interconnections on the system.

Even with this careful attention to planning, with a lack of granular visibility, distribution system operators will need to perform unplanned DER curtailment to protect the system. The curtailment will be more widespread ultimately resulting in the need to institute DER curtailment on a seasonal basis to ensure voltage and thermal overloads are minimized using conservative assumptions because of the lack of real-time visibility. This DER curtailment inhibits the achievement of the Climate Mandate. DER-related distribution planning and operating issues of this nature are starting in Rhode Island Energy in isolated areas and are anticipated to become more systematic as DER penetrations increase.

To correct operational issues on the system today, distribution system operators utilize pole top reclosers at each large solar PV site to disconnect the DER when the distribution system is in jeopardy. With deployment of grid modernization DER curtailment will be minimized due to having situational awareness and the ability to manage DER output to align with load and system capabilities which will create significant value to Rhode Island Energy consumers and enable the achievement of the State's Climate Mandates.

- **FERC Order No. 2222 and the Role of Rhode Island Energy**

  FERC Order No. 2222 is a recent order that is directed at ISO-NE and the other regional transmission operators ("RTOs") to allow DER located on the electric distribution system to participate in the RTO organized markets (e.g., the capacity, energy, ancillary service, and demand response markets). It is designed to support the electric grid of the future and to promote competition in electric markets by removing the barriers preventing DER from competing on a level playing field in the organized capacity, energy and ancillary services markets run by RTOs. DER, small and large (typically from 1 kW to 10,000 kW) that are located on the distribution system or behind the customer meter can participate as new sources of energy and grid services. They may include electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage or EV and their charging equipment. FERC Order No. 2222 allows several sources of distributed electricity to aggregate to satisfy minimum size and performance requirements that each may not be able to meet individually. This rule will likely increase the penetration of DER on Rhode Island Energy's electric distribution system and, thereby, increase the complexity of distribution system operation.

While FERC Order No. 2222 is silent on the role of reliability, it explains that state and local authorities remain responsible for the interconnection of individual DER for the purpose of participating in wholesale markets through a DER aggregation. Rhode Island Energy's distribution control center needs to take actions such as voltage reduction, load shedding, and generation curtailment on the distribution system to protect bulk system reliability when the needs occur and to fulfill the responsibility and obligation to maintain safety and reliability of the Rhode Island Energy electric distribution system. This includes – for 8,760 hours per year – maintaining distribution system voltage within acceptable limits, preventing equipment overloads, preventing outages, and restoring service rapidly after storms or other disturbances. To fulfill this operational responsibility, Rhode Island Energy's distribution operations role now and in the future is as follows:

- Plan and operate a safe, reliable, and cost-effective decentralized grid with a high penetration of DER and two-way power flow.
- Enable and facilitate DER interconnection, aggregation, and management and control for safety and reliability.
- Keep network costs down and reliability high utilizing DER and traditional investments;
- Viewed as a neutral operator trusted by regulators and consumers to fairly operate the grid.
- Manage a decentralized grid and perform required actions, protect reliability, meet stakeholder needs and balance load and generation at the distribution level to maintain stability.

Grid modernization, therefore, will enable the Company to cost-effectively enhance reliability and safety and provide customers and DER developers with better access to the electric distribution system compared to a future without grid modernization, including:

- Reliability Management: Grid Modernization investments enable distribution system operators to discover, locate, and resolve power outages in an informed, orderly, efficient, and timely manner. Operations are improved because it enables automated service restoration of unaffected segments, allows current information to be captured and analyzed, and provides meter-level outage information that can be used to better identify and isolate distribution system faults.
- Improved Situational Awareness: Grid modernization investments that are enhanced with AMF[54] information will provide distribution system operators with necessary situational awareness from grid and grid-edge sensing that can detect voltage anomalies and pinpoint system outages that are occurring across the system on a granular basis. This is needed for operators to have visibility to unforeseen power flows and voltage fluctuation from intermittent and uncertain DER in order to operate the system reliably and safely.

[54] The AMF Business Case was submitted in November 2022 to replace AMR technology which among other things, is reaching the end of its design life, is obsolete and will not scale.

- Improved System Control: Grid modernization provides real-time direct or indirect control, or coordination of advanced field devices and DER through pricing and/or engineering signals to optimize network operations and to better manage the reliability and resilience of the system. Numerous benefits are achieved such as added customer value, mitigation of thermal constraints, peak demand shifting, improved system resiliency, automatic service restoration, voltage optimization and reduced DER curtailment.
- Reduced DER Interconnection Costs: DER developers and customers will experience lower DER interconnection and other costs due to the ability of the Company to control power flows autonomously or remotely on the distribution system rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to interconnect DER. Reducing interconnection costs is expected to result in fewer DER project applications being reduced in size or cancelled altogether.
- Improved DER Operation: DER developers and customers will be able to continue to operate DER in the future without significant energy curtailment due to the ability of the Company to optimize DER load and apply DER Monitor/Manage to adjust output when system violations are imminent, rather than relying on seasonal curtailment to maintain thermal and voltage compliance.[55] Reduced DER curtailment is expected to result in higher DER utilization that can support continued adoption of renewable DG and accelerated adoption of EVs and other DER throughout the State.
- Improved DER Experience: Grid modernization investments enable improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes (e.g., flexible interconnection options, reductions in time to interconnect), and better customer and third-party information sharing and services.

To fulfill this vision with a modern-day grid will require grid modernization functionality that is fortified with granular information from AMF to provide necessary visibility and added system control for successful planning and operations.

2.6 Customer Needs

Customers increasingly want cleaner, more reliable, and more affordable energy that they can manage and control. Grid modernization investments enable the Company to meet customers' evolving behavior and expectations by providing them with more energy savings opportunities, cleaner energy options, simpler and lower-cost DER interconnections, reliability improvements, and greater choice and control in addressing their energy needs compared to a future without grid modernization, including:

[55] Seasonal curtailment means the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the system design limitations of the system.

- *Lower Energy Use:* Customer's will have more opportunities to reduce their energy use due to the ability to use energy insights as described in the AMF filing and will save money because distribution feeders will operate at lower overall voltages
- *Cleaner Energy:* Customers will have a smaller carbon footprint due to reduced energy use and increased utilization of renewable resources
- *Affordable DER Adoption:* Customers will have more affordable options to invest in their own DER technologies in areas where these technologies are most cost-effective
- *Improved Reliability:* Customers will experience reduced outage restoration times due to the ability of the Company to more quickly locate and isolate a fault and restore power
- *Greater Customer Control:* Customers will have better control over their energy bills with the ability to take action based on enhanced energy use insights, integrating AMF with in-home technologies, and responding to future pricing mechanisms

If the Company takes a "do nothing" approach, customers will not have important insights into or control over their energy use, and they will miss out on substantial energy savings, reliability improvements, and important health and societal benefits like air pollutant emissions reductions. In addition, customers and developers wishing to install renewable DG will face rapidly increasing interconnection costs, and customers will face higher costs (and/or lower benefits) to adopt other DER like EVs, energy storage, and DR, which will limit customer choice and control. With GMP, and especially when implemented with AMF, customers will benefit from enhanced outage and restoration management, and enhanced control over energy management and costs, including improved access to timely energy usage data, personalized insights and recommendations on ways to save money throughout their billing cycle, and greater access to third-party vendors offering innovative energy solutions.

In addition to these changing customer experience expectations, the electric distribution system needs to be managed more granularly, both in time and location, to continue to serve customers safely and reliably under changing grid conditions. The available technology to operate electric distribution systems has advanced so that now is an appropriate time to implement new solutions that will cost effectively address today's constraints while being flexible enough to expand in capability to address future needs and opportunities as they evolve.

2.7 Clean Energy Needs

The Company is committed to enabling Rhode Island's Climate Mandates and believes this GMP represents investments that are necessary to do so by enabling greater customer energy savings and DER adoption. Enabling DER adoption, in particular renewable DG, EV, and EHP adoption, is a key driver for meeting the State's Climate Mandates because it will enable customers to reduce their overall emissions, including transportation related emissions that make up 40% of the State's carbon dioxide emissions.[56] Grid modernization investments will help reduce the costs and other barriers to interconnect new DER in Rhode Island, which will drive more DER adoption and investment in the State, further enabling the Climate Mandates.

If the Company takes a "do nothing" approach and does not invest in well-coordinated and integrated grid modernization investments, increasing interconnection costs will slow renewable DG adoption rates below the current level, EV charging infrastructure will be more costly, and customer participation with DER and energy efficiency programs will be limited. These consequences of a "do nothing" approach will put some of the State's ambitious Climate Mandates out of reach.

[56] *See N.* 27, *supra*.

Section 3

SECTION 3: Functionalities Needed to Transform the Grid

In response to present and future unmet operational, customer and clean energy needs, this section describes grid modernization capability that is necessary for success with a modern-day grid.

3.1 Modern-Day Grid Requirements for Successful Transformation

As discussed in Sections 1.5 and 1.6, above, the transition to the modern-day grid is occurring today and is expected to continue with the proliferation of DER interconnections.

DER are being located across the distribution system at a rapid pace. These are primarily commercial/ground mounted and increasingly residential/ rooftop mounted Solar PV. These DER now cause reverse power flow with varying source strength due to configuration, DER output, and penetration, have intermittent output, and cause voltage control problems due to power flow volatility. Additional factors adding complexity to the operation of the distribution system are EV charging; gas to EHP conversion; the need to improve reliability of the system (e.g., identify and clear faults automatically, switch load between feeders during disturbances); establish a robust VVO/CVR system to reduce energy usage; and establish TVRs for consumers. These factors are affecting the seasonal and daily variability of demand and must be met in a safe and reliable manner by the electric distribution system. This new and growing complexity requires visibility and situational awareness and increased control capability of the distribution network that is aided by automation and software to make it possible to manage the system in a much more dynamic manner. Because of the current characteristics of the Rhode Island Energy electric distribution system, the Company believes it is not possible to continue to provide service reliably and safely with the status quo. Because of the current characteristics of the Rhode Island Energy electric distribution system, the Company believes it is not possible to continue to provide service reliably and safely with the status quo. The functionalities proposed in this GMP are needed now to meet unmet operational, customer, and clean energy needs.

Rhode Island Energy distribution system operators must have greater operational visibility and control to ensure safe and reliable operations and to have more dynamic interaction with customers so they can make more informed decisions and feel empowered to take more active control of their energy usage. Collectively, this presents an emerging need for continuous two-way flows of data and information between Rhode Island Energy and its customers, driving the need to upgrade the Rhode Island Energy electric metering systems with modernized AMF technology. The Rhode Island Energy AMF meters and associated systems (filed separately in Docket No. 22-49-EL) provides 15-minute granular interval data to update the network model. AMF can also remotely connect/disconnect service, notify operators of power outages and restorations, and enable the delivery of usage information to consumers and market participants. AMF technology will be used to establish a physical network that, along with grid modernization field devices and new control center operational systems, will enable operators to remotely visualize the distribution system; predict operational issues and take correct actions before they occur; respond to sudden outages, restore service more rapidly; minimize curtailment of DER; reduce peak demand; and avoid other major capital costs for infrastructure.

Rhode Island Energy has determined that the current levels of renewable DG adoption will need to continue, and beneficial electrification adoption will need to increase significantly to achieve the Rhode Island Climate Mandates. The Company also notes the following challenges that are driving the need for AMF and grid modernization. These challenges are present in some areas of Rhode Island Energy today and will become more prevalent as DER penetration increases.

- Visibility, situational awareness, and control of the distribution system and the DER connected to it will be essential to protect safety and reliability of the Rhode Island Energy system.
- Although there will be some coincidence between commercial “workplace” EV charging and the timing of solar DG injections, there is generally a mismatch between solar DG injections and typical late day and evening residential EV charging.
- High levels of renewable DG adoption will impact the grid more significantly during light loading (e.g., off-peak) periods than peak periods. During light loading periods, significant renewable DG curtailment may be required.
- High penetrations of DER will significantly impact voltage regulation. Beneficial electrification will lead to more low voltage violations, and renewable DG injections will lead to more high voltage violations during light loading periods. Therefore, advanced voltage control schemes will be required to manage voltage during both on-peak and light loading periods.
- Significant swings in loading and the increasing prevalence of two-way power flows caused by renewable DG will require more adaptive relay protection schemes to properly coordinate circuit breakers to ensure worker safety and the reliable operation of the grid
- The Company will need enhanced data handling and processing power for both distribution system planning and real-time grid operations.

3.2 Required GMP Capabilities and Functionalities

Grid modernization functionalities were determined that are necessary to address the present and anticipated future challenges and that are consistent with the GMP objectives. To identify the full set of potential grid modernization functionalities that could address the challenges, the functionalities identified in the DOE Modern Grid Initiative Next Generation Distribution System Platforms (“DSPx”) guidance for applicability in Rhode Island during the horizon of the GMP was considered.[57] At a high

[57] DOE’s Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are

level, it was determined that the capabilities that are needed to meet unmet operational, customer and Climate Mandate needs are as follows:

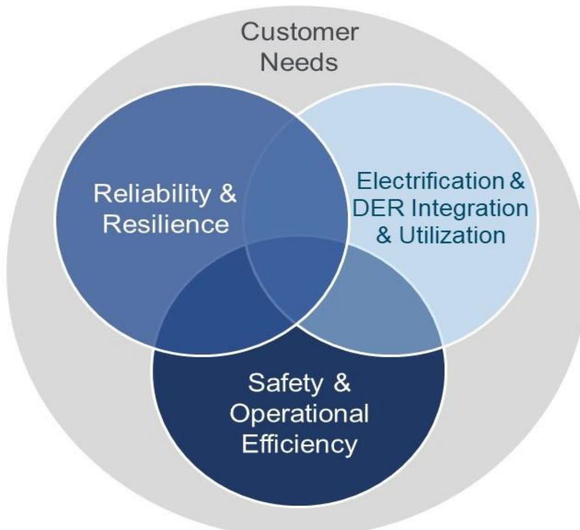
- Customer Enablement
- System Monitoring and Control
- System Optimization
- Data Acquisition
- System Modeling and Analytics

The DOE has been working with state regulators, the utility industry, energy services companies, and technology developers to determine the functional requirements for a modern distribution grid that provides enhanced safety, reliability, resilience, and operational efficiency, and integrates and utilizes DER.[58] The objective is to develop a common framework for distribution grid modernization that establishes a consistent understanding of functional requirements necessary to inform investments in grid modernization and serve as a guide for the industry. The resulting taxonomy framework provides a line of sight between policy objectives, desired attributes of a modern grid platform, functional requirements, and the technology that is needed. The framework below in Figure 3.1 has been adopted for Rhode Island Energy to illustrate the scope of the GMP where new functions are defined as an added layer to enhance safety, operational efficiency, reliability, and resilience of the modern-day grid.

available on the Pacific Northwest Laboratory's website, https://gridarchitecture.pnnl.gov/moderngrid-distribution-project.aspx

[58] U.S. Department of Energy, *Modern Distribution Grid Project—Volume I*, Pacific Northwest Laboratory, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Figure 3.1: Grid Modernization Scope



Using the DOE grid modernization framework as a guide, functionalities were defined to address present and anticipated future needs that achieved the desired capabilities. Based on this evaluation, the following set of necessary grid modernization functionalities for Rhode Island were selected.

Figure 3.2: Rhode Island Grid Modernization Capabilities and Functionalities

Grid Modernization Capability	Grid Modernization Functionality
Customer Enablement	Advanced Metering (Customer Information, Advanced Pricing, Remote Metering) Distribution System Information Sharing
Monitoring & Control	Observability (Monitoring & Sensing) Distribution grid control (i.e., voltage control and fault management for compliance, flow control and state estimation) DER Management
Optimization	Voltage Control for Optimization Reliability Management DER Management
Data Acquisition	Operational Information Management Cyber Security Operational Telecommunications
System Modeling & Analytics	Distribution System Representation (Network Models) Grid Optimization

3.3 Grid Modernization Functionality Definitions

Definitions for the functionalities are provided below. The definitions are informed by the DOE DSPx Modern Distribution Grid guidelines.[59] The functionalities have been divided into two Tiers: Tier 1 are functionalities that relate to Customer Enablement, Monitoring and Control, and Optimization capabilities and generally represent the Physical layer in the Grid Modernization Pyramid in Section 1.7. Tier 2 Functionalities are cross cutting to all Tier 1 Functionalities. They may not have direct benefit impacts themselves, but they are necessary to enable most, if not all, benefits of the Tier 1 Functionalities. Tier 2 examples include Underlying IT Infrastructure, Cyber Services, Data Acquisition, System Modeling, and Analytics which represent the upper layers in the Grid Modernization Pyramid.

[59] DOE's Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are available on the Pacific Northwest Laboratory's website, https://gridarchitecture.pnnl.gov/moderngrid-distribution-project.aspx

Tier 1 Functionalities:

- **Customer Enablement:** This functionality is achieved by providing customers with better and more timely information to make better energy choices, providing pricing options for increased affordability, and a range of functionality through AMF. All of these are included in the AMF Business Case including the integration of AMF granular information into ADMS.

  - *Customer Information:* Access to customer energy use data by customers and customer-designated entities, complying with privacy and confidentiality requirements and utilizing standard data formats and data exchange protocols. This may include appropriate access to historical and real-time energy consumption, billing related information, service quality data, as well as outage information collected by distribution services provider and/or retail energy services provider.
  - *Advanced Pricing:* Pricing that can change in response to various factors such as time, variable peak, location, and proximity to load, resource, supply conditions, system conditions, incentives/penalties, and "controllability" of supply and demand resources.
  - *Remote Metering:* Advanced meters and telecommunications network capable of remotely capturing and transmitting customer energy usage data and remotely connecting and disconnecting electric service in near real-time. This functionality results in operational efficiencies from eliminating meter reading, investigations and visits to connect and disconnect service.
  - *Distribution System Information Sharing:* Distribution system data sharing that supports intended use cases for DER integration with mutual sharing between customers, third parties and utilities, complying with privacy and confidentially requirements, to promote customer choice and integration of DER into planning and operations. This includes appropriate access to historical system and forecast planning data (e.g., load profiles, peak-demand, hosting capacity, beneficial DER locations, interconnection queue, voltage, and thermal limits) in standardized formats.

- **Observability (Monitoring & Sensing):** Ability to provide actionable information on the operating state and condition of the distribution grid, grid and DER assets, and environmental conditions necessary to operate the electric system safely, securely, and reliably. It includes visibility, which is the ability to obtain timely sensing and measurement data.
- **Power Quality Management:** Process of ensuring proper power form, including mitigating voltage transients and waveform distortions, such as voltage sags, surges, and harmonic distortion as well as momentary outages.
- **Distribution Grid Control:** Ability to manage distribution power flows while maintaining distribution operational parameters (e.g., voltage, reactive power, and power quality) within

specific operating ranges through the application of performance criteria to the dynamic management of grid devices and DER in response to changes in load and injected power flows, and system disturbances.

- **Grid Optimization:** Analytical functionality integrated with decision support systems and/or operational controls to optimize the performance of grid reliability, resilience, efficiency, hosting capacity, as well as related work and resource management.
- **Reliability Management:** Processes and systems that enable distribution system operators to discover, locate, and resolve power outages in an informed, orderly, efficient, and timely manner. The reliability management function involves operations to capture and analyze fault current indicator, meter-level outage information, and real-time customer-provided information on outages to improve the identification and isolation of electric distribution system faults, as well as service restoration of unaffected segments.
- **DER Management:** Real-time monitoring and control or coordination of DER to optimize network operations, to maintain the reliability and resilience of the system and to provide more cost-effective solutions for viable DER interconnections that will increase hosting capacity.

Tier 2 Functionalities:

- **Distribution System Representation (Network Models):** Topological model of the physical distribution system, and customer and DER connectivity (including asset characteristics) that reflects dynamic changes to the state of the system.
- **Operational Analysis & Forecasting:** Operational analysis involves the dynamic assessment of the state of the distribution system to inform real-time contingency planning, system operations including switching plans, and operational controls and DER dispatch. Operational forecasting uses a combination of measured data and analytics to develop short-term (minutes, hours, days) projections for operational scheduling, management, and optimization purposes.
- **Operational Information Management:** Operational data recording, processing, and storage used to support operational businesses functions and related processes.
- **Cyber Security:** Protection of computer systems from theft or damage to the hardware, software or the information on them, as well as from disruption or misdirection of the services they provide. It includes controlling physical access to the hardware, as well as protecting against harm that may come via network access, data and code injection, and due to malpractice by operators, or due to deviation from secure procedures.
- **Communications:** Communication protocols, technologies, and assets that are present between operating centers and substations, and extends into the field to controllable advanced field devices (e.g., switches, capacitor banks, protective devices, meters and DER

etc.) on local feeders. The performance and security requirements of communications networks for mission-critical uses, such as the electric grid, are significantly greater than public networks, internet service, and standard enterprise networks. Communications that support electric utility operations need to maintain highly reliable connectivity under both normal and degraded system operating conditions (e.g., electrical noise, equipment failure, and physical attacks). However, no communication system is invulnerable to failure, making it a key modern grid design requirement for systems to operate safely and reliably in the event of loss of communication infrastructure connectivity.

3.4 Expected Benefit Impacts Assessment

The potential benefit impacts for each functionality are provided below in Figure 3.3 and Figure 3.4 for each grid modernization functionality.

Figure 3.3: Expected Benefit Impacts for Tier 1 Functionality

Grid Modernization Functionality	Expected Benefit Impacts
Customer Engagement	Reduces system capacity requirements and customer energy use by encouraging customers to reduce their energy use based on enhanced insights (such as high usage alerts) from more granular, timely energy usage data; and potential integration with in-home technologies. • Enhances customer choice and control by providing customers with improved energy usage information and access to third party service providers; empowers customers to better understand and prioritize among solutions to best manage their energy usage and costs; and allows for innovative demand-side management programs. • Reduces system capacity requirements and customer energy costs by enabling customers to respond to price signals that can reduce demand for energy during peak demand periods, and/or increase demand for energy during negative load (i.e., excess renewable DG) periods. Improves operational efficiency by enabling the Company to eliminate O&M costs associated with meter reading, investigations, and connect/disconnect service visits. • Reduce average outage duration for customers due to improved outage notification. • Enables improved DER location selection, streamlines DER interconnection processes, reduces time to interconnect, and improves customer and third party information sharing and services by showing customers and DER providers where the most cost-effective interconnection locations are on the distribution system.
Observability (Monitoring & Sensing)	• Enables system planners and operators to design and operate the distribution system in a more flexible and efficient manner. This functionality is a foundational element and supports all other key functionalities.
Power Quality Management	• Reduces system capacity requirements and customer energy use by enabling the distribution system operator to manage voltage impacts of renewable DER and operate distribution feeders at lower overall voltages (within ANSI limits), which reduces electricity consumption and peak demand from customer appliances.
Distribution Grid Control	• Enables the distribution system operator to rearrange the distribution feeders and maximize the load-to-generation balance to avoid thermal issues.
Grid Optimization	• Enables the distribution system operator to control power flows autonomously or remotely on the distribution system and optimize power output from DER rather than investing in traditional “wires” solutions (e.g., reconductoring, substation upgrades) to relieve constraints.

Reliability Management	• Reduces customer outage time by enabling the distribution system operator to quickly identify and reconfigure the system rather than waiting for phone calls from customers to identify an outage, and field crews to locate and restore outages. Reduces customer outage time by enabling the distribution system operator to quickly develop efficient and optimal switch orders.
DER Management	Reduces DG curtailment by enabling the distribution system operator to manage DER and optimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints. • Streamlines DER interconnections by enabling larger and lower cost DER interconnections.

Figure 3.4: Expected Benefit Impacts for Tier 2 Functionalities

Grid Modernization Functionality	Expected Benefit Impacts
Distribution System Representation (Network Models)	• Provides a topological model of the physical distribution system and customer and DER connectivity. This functionality is a foundational element and supports all other key functionalities.
Operational Analysis & Forecasting	• Provides the ability to perform dynamic assessment of the state of the distribution system to inform real-time contingency planning, system operations including switching plans, and operational controls and DER dispatch. This functionality is a foundational element and supports all other key functionalities.
Operational Information Management	• Provides operational data recording, processing, and storage to support operational businesses functions and processes. This functionality is a foundational element and supports all other key functionalities.
Cyber Security	• Provides protection of cyber assets (e.g., computer hardware and software, information) from theft, damage, disruption or misdirection of the services they provide. This functionality is a foundational element and supports all other key functionalities.
Communications	• Provides highly reliable connectivity under both normal and degraded system operating conditions. This functionality is a foundational element and supports all other key functionalities.

3.5 GMP Impacts to Load Management Initiatives/Programs

With granular data obtained by ADMS, communications, advanced field devices and AMF, the electric distribution system could more effectively progress residential and small commercial DER market-facing or customer-facing programs. Likewise, the effectiveness of the GMP solutions will be impacted by the pace, scale, and effectiveness of various DER market-facing and customer-facing programs, particularly load management programs. Customer-facing load management programs, like EE and DR programs, can be used to lower the cost of wholesale electricity, reduce the bulk system's peak demand, and address generation, transmission, and distribution constraints. DER market-facing load management programs are still evaluating the role that DER can play in helping to address distribution-level constraints and reducing distribution-level peak demand. In the future, under expected DER penetration scenarios, load management programs including DR, EE, non-wire alternatives ("NWA"), EV, and Energy Storage programs can be used in combination with TVR and/or new DG tariffs to not only reduce bulk and distribution-level peak loads, but also shift customer loads to times when excessive DG output power exceeds the grid's ability to accommodate the load. Details are provided in Section 8. The following current and potential future load management programs are expected to impact the evolution of grid modernization for Rhode Island Energy:

1) **Energy Efficiency**: Although today's energy efficiency portfolio generates system benefits at capacity, transmission, and distribution levels, the portfolio is generally focused on bulk system level (capacity and transmission) and not the constraints of the local distribution system. The Company envisions future energy efficiency customer offerings that will optimize demand side resources to achieve an efficient and resilient grid on both the wholesale and distribution levels. The Company has been working, and will continue to work, to progress the integration of Distribution Planning with Energy Efficiency to further identify opportunities to address constraints on the distribution system, which can lower the cost of electricity delivery. New enhancements to the Energy Efficiency program will be proposed through annual Energy Efficiency Plan filings.
2) **Demand Response ("DR")**: Building within the energy efficiency programs, both residential and commercial DR programs play a critical role in helping Rhode Island contribute to peak load reduction and improving power quality, which produces system capacity benefits at the transmission, and distribution levels. However, like the rest of the energy efficiency portfolio, DR today is generally focused on the bulk system level and does not include response to the constraints of the local distribution system. The Company is looking into extending the DR programs to provide support to distribution-level NWAs using the new grid modernization functionality and infrastructure provided by the Foundational Investments. New enhancements to the DR program will be proposed through annual Energy Efficiency Plan or SRP filings. In the future, the new ADMS - DERMS deployment will enable DR performance for more customer DER. In addition, the deployment of AMF for

residential and small commercial customers will establish a basis for TVR implementation, to provide improved price signals to residential and small commercial customers.

3) **Non-Wires Alternatives (NWA)**: NWA is an inclusive term for any targeted electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment." NWA projects are required to meet the specified electrical grid need and be cost-effective compared to the traditional "wires" investment. An NWA project can include any action, strategy, program, or technology that meets this definition and these requirements. In the near-term, grid modernization will help identify and fairly compensate NWA projects, which may result in an increase of NWA projects. The NWA process will also benefit from more granular system operational data, customer load data, and other information from AMF and advanced field devices, as planners will be able to better evaluate and forecast system loads and better predict the timing (e.g., time of day, month of year) of potential thermal or voltage issues. This refined understanding of the system constraints will enable a better understanding of the NWA need, permit NWA design optimization, and facilitate more cost-effective NWA projects. In the longer term, grid modernization, combined with new revised rules on DG operation and TVR, may reduce or possibly eliminate the need for what are considered NWAs today; as the integration of TVR, energy efficiency, DG, and DR become part of the modern grid.
4) **Energy Storage**: The Energy Storage construct approved in Docket No. 4770 will support customers in adopting energy storage technologies in the near-term. This program can positively contribute to changes in customer preferences for energy management and help uncover the best value proposition for energy storage. The current residential, commercial, and industrial customer DR programs also include the management of behind-the-meter (BTM) energy storage for peak load reduction. In the future, with more granular system operational data enabled by advanced field devices and AMF, and the overall management and control enabled by ADMS - DERMS and DER Monitor/Manage, customer's energy storage assets can be used to help manage load on the distribution system for the benefit of all customers. New enhancements to energy storage programs will be proposed through future rate cases, annual Energy Efficiency Plans, and/or the System Reliability ("SRP") plans.
5) **Transportation and Heat Electrification**: The Electric Transportation Initiative approved in Docket No. 4770 and future Beneficial Heat Electrification programs will support customers in adopting electrification technologies in the near-term. These programs can positively contribute to changes in customer preferences for a shift towards clean energy and electrification that customers seek. If not properly managed, new electrification loads can have a significant negative impact on the distribution system by increasing peak load. However, if properly managed through a well-coordinated and integrated grid modernization effort employs load management techniques along with TVR, these new electrification loads can be shifted away from periods of peak demand on the distribution system to periods of

low demand and/or high DG output, which can reduce distribution infrastructure investment, and, in the future, help minimize negative load periods due to excess renewable DG output. New enhancements to electrification programs will be proposed through future rate cases, annual Energy Efficiency Plans, and/or the SRP plans.

These benefits are considered in the analysis of the comprehensive Distribution Study presented in Section 5 and clearly demonstrate how the grid modernization functionalities that are proposed in this GMP are vital and enable load management programs on the distribution system to add value to reliability and consumer savings.

Section 4

SECTION 4: GMP Technology Overview

This Section describes the specific grid modernization technology elements that contribute to and are integrated to become grid modernization solutions and how these solutions and associated functionality mitigate safety and reliability issues on the distribution system and provide benefits.

4.1 Proposed Solutions

The most appropriate solutions that enable the key functionalities were identified drawing upon PPL's grid modernization experience and consulting with external experts to ensure the most cost-effective solutions were selected for the GMP horizon. Figure 4.1 summarizes the solutions to progress each of the Tier 1 functionalities that have been identified.

4.1: Solutions Selected for Tier 1 Functionalities[60]

Solutions

Functionality -->	Customer Enablement	Observability	Power Quality Management	Distribution Grid Control	Grid Optimization	Reliability Management	DER Management
Foundational							
ADMS/DERMS Advanced	x	x	x	x	x	x	x
Advanced Capacitors & Regulators		x	x	x	x		
Advanced Reclosers		x		x	x	x	
DER Monitor/Manage	x	x	x	x	x	x	x
Microprocessor Relays		x		x	x	x	
Communications	x	x	x	x	x	x	x
IT Infrastructure	x	x	x	x	x	x	x
Mobile Dispatch		x				x	
Existing							
AMF Meters	x	x	x	x	x	x	x
Customer Portal	x				x	x	
DG Portal	x				x	x	x
GIS-Network Model		x	x	x	x	x	x
Future							
Energy Storage	x	x	x	x	x	x	x
TVR	x				x	x	x
V2G	x				x	x	x
Single Phase Reclosers				x		x	
Dynamic Line Ratings					x	x	

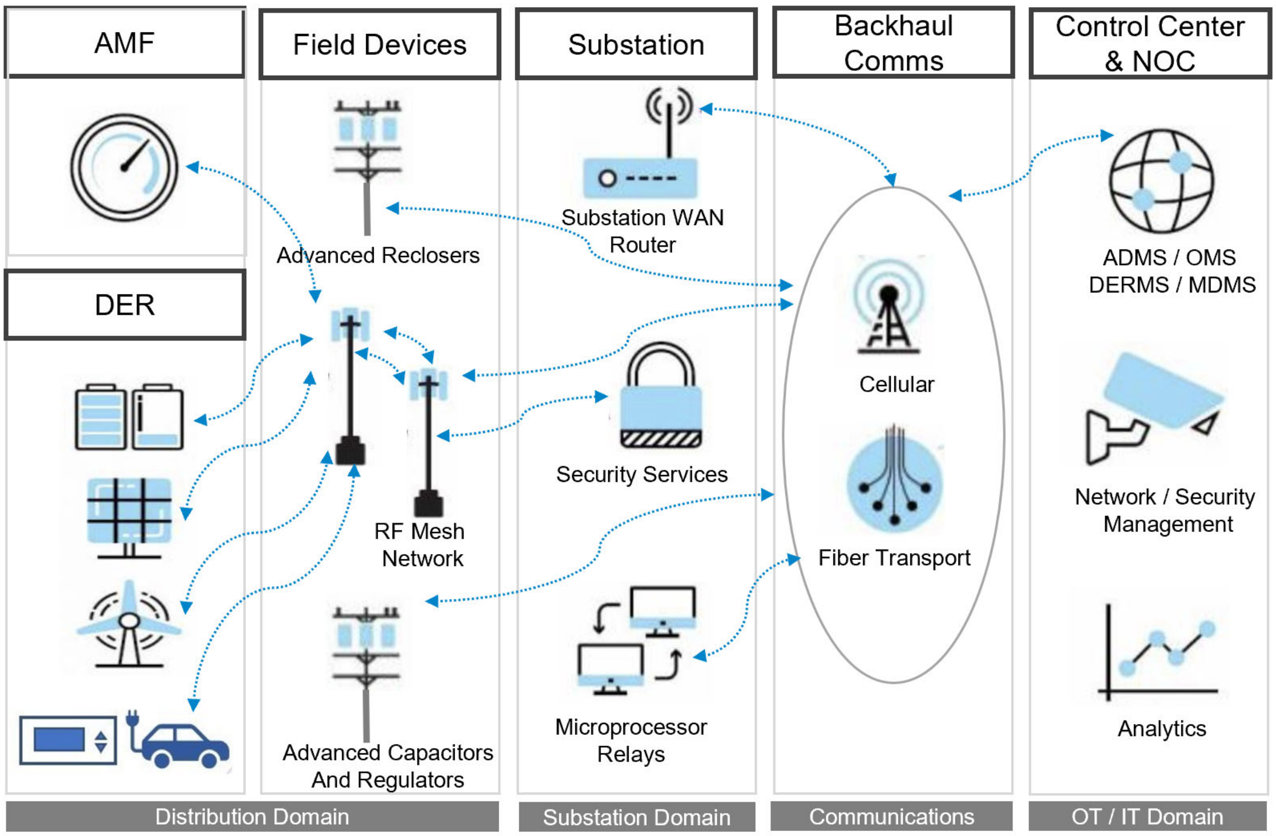
[60] AMF meters are included within the "Existing Functionalities" in Figure 4.1 based on the anticipated implementation timeline as set forth in the Company's AMF Business Case, which is currently pending before the PUC in Docket No. 22-49-EL.

The GMP solutions are very interrelated when considering value propositions that will be achieved through effective and continued integration. Functionalities can be enabled by more than one solution, and a number of the solutions contribute to enabling more than one grid modernization functionality. In practice, most functionalities require more solutions than are listed. For example, all Tier 1 functionalities require Tier 2 functionalities such as Underlying IT Infrastructure, Appropriate Cyber Services, Communications, and Network Management.

4.2 Description of GMP Solutions

To achieve the GMP functionality that is required to operate the Rhode Island Energy electric distribution system in a safe and reliable manner, the underlying solutions need to be fully integrated. As illustrated in Figure 4.2 below, the proposed GMP solutions are organized into five integrated facets: (1) a network of AMF electric meters and DER Monitor/Manage devices capable of capturing grid-edge data at defined intervals and supporting grid-edge applications. This includes customer systems such as billing and a Customer Portal to provide energy usage data access, insights, and service offerings to enable customer energy management (included in AMF filing); (2) advanced field devices including capacitors, regulators, and reclosers that are capable of communicating and receiving settings remotely; (3) interconnected secure communications consisting of cellular, two-way mesh communications network and IT infrastructure for transmitting the data and control signals that uses a cellular or fiber backhaul technology; (4) microprocessor relays and substation routers in the substation; and (5) an IT platform that is anchored with ADMS, peripheral systems and cybersecurity protections to securely and efficiently collect, validate, store and manage the data.

Figure 4.2: GMP Functionalities Comprise of Solutions in Five Integrated Facets



4.3 Definition Summary of Grid Modernization Solutions

Figure 4.3 below summarizes each solution, what it is and what it does for grid modernization within the context of the GMP. Detailed descriptions are presented in the GMP Deployment Plan in Attachment H.

Figure 4.3: Summary of Grid Modernization Solutions

Grid Modernization Solutions	What is it? What does it do?
AMF	Smart metering technology that will capture and transmit customer energy usage data on an hourly or sub-hourly basis. This technology enables customer energy management (e.g., Customer Portal), customer energy information sharing (e.g., Green Button Connect), advanced pricing options (e.g., TVR), remote metering and service (e.g., on/off) capabilities, and granular distribution system information.
System Data Portal	Internet-based portal that provides distribution data to Rhode Island customers and third-party DER developers, so they can identify areas where DER will likely be most beneficial and avoid areas where integrating DER may be problematic or costly. The proposed investment encompasses continued maintenance and development of the existing portal with relevant distribution system and planning information to facilitate DER integration in the best locations and as cost-effectively as possible.
Advanced Capacitors & Regulators	Deployment of capacitors and regulators with advanced controls and sensing to manage voltage within ANSI voltage standards, targeting those areas and feeders with existing DER penetration and the greatest risk of voltage violations.
Advanced Reclosers	Deployment of advanced reclosers that have controls and sensing to ensure distribution equipment is operated within its rated capacity and that faults on the system are cleared efficiently. Operate in conjunction with ADMS – FLISR targeting those areas and feeders with greatest needs for reliability improvement and where there is existing DER penetration that presents risk of possible protection coordination challenges.
Microprocessor Relays	Microprocessor relays are computer based and use programmable logic. The logic dictates how the relay will perform its main duty of protecting the electrical system. For example, if a fault is detected, the protective relay will respond by tripping and potentially locking out a breaker, preventing major equipment and system damage Settings can be changed remotely.

GIS Data	GIS software and processes will be used as the authoritative source for distribution asset information and network configuration (i.e., connected model) to support the network model for ADMS and other requirements of the integrated modern grid.
ADMS Basic and Advanced	Software and hardware that will support distribution control room operations by providing greater visibility, situation awareness, and optimization of the distribution system.
ADMS-based Advanced Protection	Software that will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices to ensure worker safety and the reliable operation of the grid.
Data Management	IT platform to house internal and external data (e.g., asset, meter, land development, weather, real estate) that will ensure the proper data are made available for analytics and that these data are properly controlled.
Enterprise Network Model	An IT platform that includes a topical representation of the power system and its connectivity, enabling power system analysis to make operating and planning decisions based upon information that is available in real-time due to the exchange of information between systems, services and devices.
Data Lake	IT service that records hundreds of thousands of pieces of raw operational data generated by intelligent electronic devices being monitored and controlled in a modernized grid SCADA system.
Cyber Services	IT services to protect customers and electric grid operations from a vast array of threats from new vectors as more devices, including third-party devices, are connected and integrated with utility operations.
Network Management	IT communications technologies that collect meter and T&D system data to support AMF and the integrated modern grid.
Fiber	Fiber communications investments to develop a secure, private fiber network to accommodate the Company's electric distribution system backhaul communication needs with improved performance, security, reliability, resiliency and cost-effectiveness.
ADMS – VVO/CVR	Deployment of software with control schemes to coordinate multiple voltage regulating devices (i.e., Advanced Capacitors & Regulators) on a feeder to achieve optimal CVR performance and reduce customer demand and energy use.
ADMS – FLISR	Software with overlaying control scheme to coordinate multiple load management devices (i.e., Advanced Reclosers & Breakers) on a feeder to achieve fast, reliable, and safe FLISR, which can reduce the frequency of customer outages and improve restoration efficiency.

ADMS – DERMS	Suite of software tools to integrate DER resources with grid operations, including integrating DER Monitor/Manage to dispatch DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution.
DER Monitor/ Manage	Field hardware that enables communications to monitor and manage DER will increase hosting capacity, reduce curtailments and assist in balancing load and generation. IEEE 1547-2018 certified Advanced Inverters provides Rhode Island Energy access to a smart inverters' second port for monitoring and managing it. Optimization will occur by providing the interval energy and voltage data at the customer level required for verification and settlement. AMF facilitates the exchange of information and/or control with DER technologies through the build-out of the AMF RF Mesh Network. See Attachment G.

4.4 Grid Modernization Solutions and Assumptions Used in the Distribution Study

Solutions used for Grid Modernization alternative in the Distribution Study are based upon having Tier 1 and Tier 2 Functionalities available through the Foundational Investments. Capability is founded on principles of leveraging AMF interval customer data, managing the distribution grid more granularly, and building a flexible grid that is reliable and safe to 1) give customers more energy choices and information; 2) ensure clean, reliable, and affordable energy to benefit Rhode Island customers over the long term; and 3) integrate more clean energy generation into distribution planning and operations for the benefit of customers.

Some of the most impactful grid modernization functionalities that are available in the Grid Modernization alternative in the Distribution Study includes added system situational awareness, customer enablement, Volt-VAR optimization, voltage management, visibility of hidden load, peak demand shifting (via VVO, TVR, Demand Response, EV charging, and Energy Efficiency), FLISR for faster restoration and System optimization that uses curtailment from advanced reclosers and increasingly DER Monitor/Manage. These are all described further in Section 6 in conjunction with the GMP Grid Modernization Solution Roadmap.

Section 5

SECTION 5: GMP Study Scope, Analysis and Results

This Section presents the purpose, scope, and results of a Distribution of the Rhode Island Energy electric system for the years 2030/2040/2050 to determine the need, portions of the cost, and benefits to achieve the Rhode Island Climate Mandates. A preliminary Transmission Study was also performed using the output of the Distribution Study, which included seasonal, peak and off-peak extremes. The Distribution Study resulted in a recommendation to proceed with the Grid Modernization alternative after considering infrastructure costs implications and other benefits. Results are presented for the system in this Section and available by Planning Area in Attachment F.

A comprehensive Distribution Study was performed to determine the avoided costs of distribution system infrastructure and other benefits of the Rhode Island Energy GMP. The study was a state-wide analysis of the Rhode Island Energy electric system to determine the most efficient/"No Regrets" investment plan to meet the state's Climate Mandates while serving Rhode Island customers reliably and safely. The Distribution Study scope included analysis of sub-transmission and distribution systems (400 distribution feeders, 56 sub-transmission lines, and associated substations). A separate Transmission Study was performed (345- and 115-kV system) utilizing the results from the Distribution Study to determine the impacts to the bulk system (*See* Section 5.10).

5.1 Managing Uncertainties from Changing Requirements

The operating requirements of the Rhode Island Energy electric system are rapidly changing as a result of the State's Climate Mandates and the change in the energy supply resource mix on the electric distribution system, and customers' interest in managing their energy needs. The key factors that are changing these requirements and conditions are:

1. DER Penetration on the sub-transmission and distribution system
    - Voltage excursions
    - Back-flow conditions
    - Hidden Load
    - Variability in daily load patterns
    - Thermal overloads
    - Safety and Reliability issues
        a) Firm versus un-firm resources
        b) Protection desensitized
2. EV Charging and its impact to demand and energy growth on the grid
3. EHP conversion and its impact to demand and energy growth on the grid
4. Deteriorating reliability performance of the Rhode Island Energy electric system (see Section 1.9).

Any planning study of the future Rhode Island Energy system must start with a model of the topology, load, and generation conditions of the existing system, but must be adaptable to the changing needs described above.

Therefore the “base case” model for this study uses the Area Planning infrastructure models but applies load and generation through 2050 that varies throughout the day, the seasons, and over the years. This is a fundamental change over previous planning efforts, which focused on static power flow at static times. To enable a time-based approach, a forecast, matching the typical Company forecast through 2036 and set to meet energy policy goals through 2050, is determined. The models are set up with this forecast to analyze every hour of the year across tens of thousands of nodes to determine the loading and voltage stress points of the distribution system. Out of the 8,760 hours in the year, the summer and winter, load and generation peaks are found and studied in detail. Two key perspectives are studied: 1) system capacity to transmit and distribute energy from generation sources to load points; and 2) load to generation balance at any point in time. The solutions are tested to verify that they solve voltage and or thermal violations, which occur over the period and that the load to generation balance is maintained.

There are a variety of major variables affecting the demands and requirements of the Distribution Study. Rhode Island Energy carefully considered these variables and made base modeling assumptions. Figure 5.1 summarizes the variables and rationales to sufficiently test the electric system.

Figure 5.1 – Variables and Study Rationale

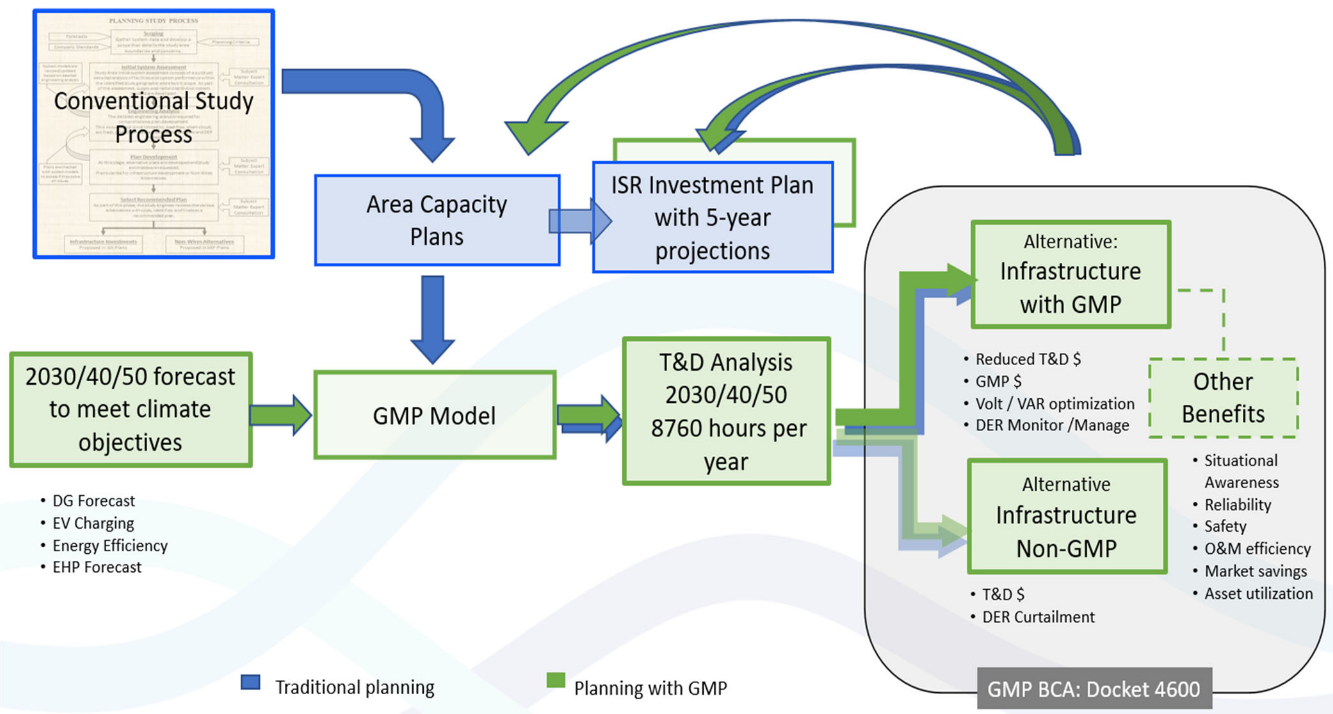
	Study Assumption	Rationale
Levels and location of DG penetration	DG distributed as 100kW sites located proportionally to load. Rural locations weighed higher than urban locations.	Distribute DG as small sites and aligned with load levels to favor No Grid Modernization analysis. Rural areas weighted due to space requirements and trends of DG.
Level, timing, and dispersion of EV charging	EVs distributed as additional load category to existing customers (households). Maximum of two EVs per customer.	Simple allocation to existing customers selected as most reasonable and balanced approach.
Level, timing, and dispersion of EHPs.	EHPs distributed as additional load category to existing customers (households).	Simple allocation to existing customers selected as most reasonable and balanced approach.
Level, timing, and dispersion of Battery Energy Storage Systems ("BESS").	BESS is considered as a solution. Size and location determined during solution development to solve system constraints	Approach optimizes BESS and ensures that BESS do not create additional system constraints.
The contributions and impacts to the load profile from TVR, Energy Efficiency, and Demand Response, which are enabled by AMF and grid modernization	TVR, Energy Efficiency, and Demand Response were set to shift energy by 3%.	Conservatively low value to evaluate grid modernization energy shifting enabling functionalities.
Evolving distribution network topology that includes infrastructure changes that are approved and implemented for capacity upgrades, retirements, etc., identified through the Area Plans	Area Plans were incorporated into the base model.	Tests energy policy levels of DG, EV, EHP against current plans to evaluate future viability.

One of the major purposes of the Distribution Study is to ensure the future improvements are prudent and viable given the range of uncertainties with load and generation. The goal is to ensure the grid modernization investments can handle a variety of possible future state scenarios at the lowest cost and with the greatest benefits. All variables could not be iterated because of the magnitude of the analysis that would be required; however, , each variable was set to reasonably consider customer and load densities, sufficiently test the electric distribution system, and not to disadvantage the alternative without grid modernization.

5.2 Distribution Study Scope and Analysis Description

The Distribution Study scope for the GMP was developed based on a forecast of energy and demand conditions expected in the years 2030/2040/2050 to achieve the State's Climate Mandates, which includes expected growth in energy efficiency, EVs, EHP, wind generation (onshore and offshore), and photovoltaic generation. The GMP Distribution Study was performed by the Rhode Island Electric distribution planning engineers responsible for the 11 Area Plans (see Figure F.1). Figure 5.2 describes how the traditional Distribution Study process was adopted for the GMP where it applied the DER forecast to the 11 Area Plans comparing the results from two infrastructure alternatives: No Grid Modernization alternative and Grid Modernization alternative.

Figure 5.2: The Distribution Study Process



1. The starting point of the process is the development of the existing and currently planned electric distribution system as defined by the completed Area Studies through the electric ISR plan process (11 Areas) which have been planned with the conventional study process shown. The specific projects developed through the Area Studies as part of the electric ISR plan process[61]. The Area Study projects are incorporated into the GMP model creating the starting year base case.
2. A forecast of 2030/40/50 load, energy, and generation that is needed to meet the State's Climate Mandates is applied to the model for analysis creating a Distribution Study base case. An 8,760-hour load flow analysis is then conducted for each study year to determine the hours of the year that create stressed loading conditions on the electric distribution system (i.e., hour of the annual summer peak, winter peak, and minimum load/off peak). This study identifies thermal overload and voltage violations that would occur during those conditions if no additional solutions were deployed.

[61] See "Investment Plan with 5-Year projections" of current and future ISR Plans.

3. Two alternatives were modeled to mitigate the voltage and thermal violations identified in Step 2.
    a. **<u>The "No Grid Modernization" Alternative</u>**. In addition to the Area Study upgrades modeled in the base case, this solution identifies additional sub-transmission and distribution upgrades necessary to obviate the identified violations in each Area Study. The study also identifies the amount of energy required to be curtailed each year (to avoid system violations) using disconnects at large DER sites without the benefit of grid modernization technology.
    b. **<u>The "Grid Modernization" Alternative</u>**. This solution models grid modernization functionality and equipment and its ability to mitigate voltage and thermal issues, and then determines the reduced amount of sub-transmission and distribution infrastructure upgrades needed to obviate remaining violations in each area. In addition, this study identifies the reduced amount of DER curtailment resulting from proposed grid modernization functionality.
4. The results from Step 3 are then fed back into the original Area Study to determine if any of these originally defined upgrades need to be modified or eliminated. This step ensures that the current upgrade solution is sound for future conditions with grid modernization and, therefore, has long range usefulness.

5.3 Base Case Development

The existing base case used for the Distribution Study was Rhode Island Energy's three-phase load-flow that was modeled in commercially available CYME software that is used for distribution system planning.[62]

System Topology Update

The topology of the existing Rhode Island Energy sub-transmission and distribution system was modified in the existing base case to represent the upgrades as defined by the current 11 Area Studies such as new or re-conductored sub-transmission or distribution lines, new or upgraded substations/transformers, retirements, etc. This created the future year topology or network configuration as currently planned and is used as the base case for the GMP analysis.

Incorporating Area Study recommendations into the GMP base case was important for two reasons: 1) ensuring that grid modernization infrastructure would not build upon retiring assets nor duplicate planned assets; and 2) ensuring that the Area Study plans would sufficiently support grid modernization needs. These reasons are highlighted by the Providence area investments. The Providence study included recommendations to eliminate certain 4kV substations, such as Geneva and Olneyville, and

[62] *See* https://www.cyme.com/software/

rebuild and expand the Admiral Street substation. Incorporating these changes into the GMP model ensured that the analysis did not utilize infrastructure on Geneva and Olneyville substations or propose new substation infrastructure that was similar electrically to the Admiral Street scope. Furthermore, with the Admiral Street configuration included, the GMP analysis could test whether Admiral Street, or a different near-term scope, should be proposed considering the original area study needs plus the future grid modernization needs.

Study Years

The study years of 2030, 2040, and 2050 were selected to ensure that the long-range effectiveness of the solutions evaluated, did align with the Climate Mandates, i.e., whether the GMP makes sound technical and economic sense now and in the future; and whether any of the currently planned Area Study upgrades need to be modified. The 2050-time frame also coincides with the recent ISO-NE study[63] that was sponsored by the New England Conference of Public Utilities Commissioners ("NECPUC") to evaluate the impacts of the clean energy initiatives to the New England bulk transmission system. Study year cases for the winter, summer, and annual off-peak conditions including 8760-hour load cycles were created for performance analysis, determination of required sub-transmission and distribution upgrades, and evaluation of alternatives. The 8,760-hour load cycle analysis identified the worst peak load demand and worst peak generation operating hours and load conditions that were then modeled on the bulk transmission system for subsequent analysis (see Section 5.9 and 5.10).

Long Range Demand, Energy and Renewable Forecast

The Company's current peak forecast was used as the basis for the GMP forecast.[64] This was done to align with other Company planning efforts and ensure consistency across the Area Studies. Figure 5.3.1 summarizes the forecast details. As can be seen from Figure 5.3.1, the forecast historically considers impacts to peak load. Specifically for 2021, the PV value of 152 megawatts is the reduction on peak for approximately 400 megawatts of nameplate generation. For grid modernization analysis, the focus is no longer on-peak impacts only; therefore, the forecast was adjusted as shown in Figure 5.3.2. Nameplate values and numbers are required instead of peak contributions to provide the necessary inputs to the models. The analysis that determined the number of cars, number of EHPs, and megawatts of solar and wind generation are described below.

[63] ISO-NE 2050 Transmission Study
[64] *See* http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_PEAK_2022_Report.pdf

Figure 5.3.1: Rhode Island Energy Peak Forecast

NECO	SUMMER 50/50 Peaks (MW) (before & after DERs)								
	-------- SYSTEM PEAK ----------		---------------------------- DER IMPACTS ------------------------------------						
Calendar Year	Reconstituted Load MW PreDER	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2021	2,260	**1,729**	(350)	(152)	1.6	(29.1)	(0.9)	(1.4)	(531)
2022	2,192	**1,738**	(370)	(50)	3.9	(33.4)	(1.3)	(2.5)	(453)
2023	2,231	**1,745**	(387)	(62)	6.1	(38.4)	(1.7)	(3.8)	(486)
2024	2,264	**1,746**	(404)	(73)	9.2	(42.4)	(2.1)	(5.3)	(518)
2025	2,299	**1,751**	(422)	(84)	13.3	(44.3)	(2.6)	(7.2)	(547)
2026	2,319	**1,746**	(440)	(95)	18.8	(44.3)	(3.0)	(9.3)	(573)
2027	2,260	**1,761**	(458)	(13)	30.2	(44.3)	(3.4)	(10.8)	(499)
2028	2,287	**1,777**	(475)	(14)	40.7	(44.3)	(3.8)	(13.6)	(510)
2029	2,312	**1,793**	(491)	(15)	53.8	(44.3)	(4.2)	(17.1)	(518)
2030	2,335	**1,812**	(507)	(16)	69.6	(44.3)	(4.7)	(21.2)	(523)
2031	2,355	**1,830**	(522)	(16)	88.2	(44.3)	(5.1)	(25.5)	(525)
2032	2,373	**1,851**	(536)	(17)	109.6	(44.3)	(5.5)	(29.5)	(523)
2033	2,389	**1,872**	(549)	(18)	133.5	(44.3)	(5.9)	(33.4)	(517)
2034	2,400	**1,891**	(562)	(18)	159.5	(44.3)	(6.3)	(37.1)	(509)
2035	2,399	**1,902**	(574)	(19)	187.6	(44.3)	(6.7)	(40.6)	(497)
2036	2,411	**1,928**	(586)	(19)	217.4	(44.3)	(7.1)	(43.9)	(483)

Figure 5.3.2: GMP Forecast[65]

GMP DER Forecast/Impact to Peak

	2030		2040		2050	
	Summer	Winter	Summer	Winter	Summer	Winter
Heat Pumps (Ea.) Forecast	54,000	54,000	325,000	325,000	400,000	400,000
Heat Pumps (MW) @ Peak	0	200	5	1310	5	2825
Solar PV Nameplate (MW) Forecast	1,500	1,500	3,400	3,400	5,000	5,000
Solar PV Nameplate (MW) @ Peak	0	0	0	0	0	0
Electric Vehicles (Ea.) Forecast	87,300	87,300	675,000	675,000	840,000	840,000
Electric Vehicles (MW) @ Peak	70	80	805	910	1010	238
RIE Peak Demand (MW)	**1,940**	**1,415**	**2,519**	**3,280**	**2,785**	**3,855**

More Distributed Generation than Load

Winter Peak

Peak Demand Doubles

As can be seen in Figure 5.3.2, the combined impact of electric heating and EV conversion will double the Rhode Island Energy peak demand by 2050. The 2021 summer peak demand was 1,800 MW and is projected to increase to 1,940 MW by 2030; 2,519 MW by 2040; and 2,785 by 2050. The winter peak demand was 1,180 MW in the winter of 2020/21. The winter peak is forecasted to increase to 1,415 MW by 2030 and 3,280 MW by 2040. The Rhode Island Energy system is forecasted to switch from being summer peaking to being winter peaking in 2034, driven predominantly by heating load electrification.

The numbers and megawatts of DER resources were developed using emissions data from the 2019 EIA report for Rhode Island assuming the State's Climate Mandates will be achieved through adoption of a combination of solar generation, wind energy production, EV, and EHP conversion. Figure 5.3.3 shows the EIA data in million metric tons of CO2 per sector.

The Climate Mandates emission goals are:

1. 45% CO2 reductions by 2030
2. 80% CO2 reductions by 2040

[65] ISO-NE forecast 59,300 RI homes with heat pumps by 2031 aligned with GMP forecast of 60,000. *See* https://www.iso-ne.com/static-assets/documents/2022/04/final_2022_heat_elec_forecast.pdf

3. Net zero (100%) CO_2 reductions by 2050

Figure 5.3.3: EIA Data – Million Metric Tons of CO2 Per Sector

Rhode Island Carbon Dioxide Emissions from Fossil Fuel Consumption (2019)		**2019 million metric tons CO2**
Residential Sector		
	Coal	0.00
	Petroleum Products	0.98
	Natural Gas	1.08
	Total	2.06
Commercial Sector		
	Coal	0.00
	Petroleum Products	0.26
	Natural Gas	0.68
	Total	0.94
Industrial Sector		
	Coal	0.00
	Petroleum Products	0.17
	Natural Gas	0.46
	Total	0.63
Transportation Sector		
	Coal	0.00
	Petroleum Products	3.79
	Natural Gas	0.14
	Total	3.93
Electric Power Sector		
	Coal	0.00
	Petroleum Products	0.01
	Natural Gas	2.81
	Total	2.81
	Grand Total	**10.37**

To determine the electric distribution system impacts, the CO_2 values were converted to British Thermal Units (BTUs) and then to megawatt*hours. First, the percent of each sector that could be converted was determined. For example, the space heating portion of the petroleum based Residential Sector was considered to be 81%. Next, end-use efficiency was applied to determine the value of energy actually used. This end use energy was shifted to the electric sector based on approximation of the Climate Mandates targets. To find the new electric sector generation needs, the efficiency of the electric technology was applied. Finally, renewable generation was added and adjusted to achieve emission goals.

Example calculation – 2019 EIA Residential – Petroleum related CO2 = 0.98 million metric tons

1. Convert to Trillion BTU = 13.4
2. Apply % of sector associated with space heating – 81% *13.4 = 10.9
3. Apply end use efficiency to find end use energy actually used
    a. Oil boiler considered 84% efficient – 84% * 10.9 = 9.16
4. Convert to end use trillion BTUs to MWh – 2,685,000
5. Shift to Electric Sector based on climate goals
    a. 2030 Shift – 20% -> 537,000 MWh
    b. 2040 Shift – 80% -> 2,148,000 MWh
    c. 2050 Shift - 100% -> 2,685,000 MWh
6. Apply electric technology efficiency to find generation need
    a. EHP average coefficient of performance – 2.98 or 298%
    b. Electric system losses – 6%
    c. Effective efficiency – 298%*94% = 280%
    d. Generation needs to supply:
        i. 2030 -> 192,000 MWh
        ii. 2040 -> 766,000 MWh
        iii. 2050 -> 958,000 MWh
7. Determine renewable allocation of generation need
    a. If all served by solar (17% AC capacity factor):
        i. 2030 -> 130 MW
        ii. 2040 -> 515 MW
        iii. 2050 -> 645 MW
    b. If all served by off-shore wind (43% AC capacity factor):
        i. 2030 -> 50 MW
        ii. 2040 -> 205 MW
        iii. 2050 -> 255 MW
    c. Establish balance between solar, onshore wind, and offshore wind generation

CO2 shifting opportunity

Energy actually used for end use

Generation need is less than energy need as a result of heat pump efficiency

The results of the emission conversion are shown in Figure 5.3.4

Figure 5.3.4: Emission Conversion to Electric Sector

Sector	Sector Detail	Sector Opportunity	2030 % Transferred	2040 % Transferred	2050 % Transferred
Transportation	EVs-Light Duty	86%	10%	80%	100%
Transportation	EVs-Heavy Duty	86%	5%	80%	100%
Residential	EHP-Oil	81%	20%	80%	100%
Residential	EHP-Natural Gas	71%	5%	80%	100%
Commercial	EHP-Oil	63%	20%	80%	100%
Commercial	EHP-Natural Gas	73%	5%	80%	100%
Industrial	EHP-Oil	3%	20%	80%	100%
Industrial	EHP-Natural Gas	12%	5%	80%	100%
Electric Power	Wind MW		1000	1150	1450
Electric Power	Solar MW		1,500	3,400	5,000

The resulting projected carbon dioxide emissions are shown in Figure 5.3.5.

Figure 5.3.5: Resulting Million Metric Tons of CO2 By Sector

Rhode Island Carbon Dioxide Emissions from Fossil Fuel Consumption		2030 million metric tons CO2	2040 million metric tons CO2	2050 million metric tons CO2
Residential Sector				
	Coal	0	0	0
	Petroleum Products	0.82	0.34	0.18
	Natural Gas	1.05	0.47	0.32
	Total	1.87	0.81	0.50
Commercial Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	0.23	0.13	0.10
	Natural Gas	0.65	0.28	0.18
	Total	0.88	0.41	0.28
Industrial Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	0.17	0.16	0.16
	Natural Gas	0.46	0.42	0.40
	Total	0.62	0.58	0.57
Transportation Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	3.40	1.15	0.52
	Natural Gas	0.14	0.14	0.14
	Total	3.53	1.29	0.65
Electric Power Sector				
	Coal	0.00	0.00	0.00
	Petroleum Products	0.00	0.00	0.00
	Natural Gas	0.76	1.19	0.35
	Total	0.76	1.19	0.35
	Grand Total	**7.67**	**4.28**	**2.35**
Percent Reduction of CO2 Opportunity		45%	80%	100%

EV Forecast

Today there are between 4,000 and 5,000 EVs operating in the state of Rhode Island.[66] This is projected to increase to 87,300 EVs by 2030; 675,000 by 2040; and 840,000 by 2050. With this forecast, most light trucks and automobiles would have been switched to electric by 2050. This assumption is a key component of the Climate Mandates requiring reduced carbon emissions.

In 2022, approximately 42% of EVs use Level 1 chargers and 58% utilize Level 2 chargers. This is projected to decrease to 20% Level 1 and increase to 80% Level 2 by 2050. The increase in Level 2 charging will be required through advances in technology driven by the need for consumers to have sufficient energy storage/driving capability to meet projected daily driving requirements. The combined impact of the increase in the number of EVs and the increase in Level 2 charging can add over 700 MW to the summer peak demand and over 1,000 MW to the winter peak demand by 2050. Over 3,600 Gwh in annual energy growth can be added to the Rhode Island Energy electric system by 2050.

To develop the EV load cycle, the U.S Department of Energy's EVI-Pro Lite tool was used.[67] EVI-Pro Lite was created to assist planning organizations to estimate how much EV charging a city or state might need to meet their goals. The model considers travel patterns, charging station details, and EV details. A significant benefit of this tool is a weekday and weekend load cycle application which provides the needed details for this GMP analysis. Load cycle inputs for the three test years are shown in Figure 5.3.6. Summer, winter and spring/fall load cycles were developed and repeated for the respective season to create an 8760-hour yearly load cycle. Figures 5.3.7 through 5.3.9 show the 2030 weekday/weekend load cycles for each season, which demonstrate how the hourly energy of the various charging methods add to create an overall stacked line EV curve.

[66] *See* https://www.dot.ri.gov/projects/EVCharging/#:~:text=There%20are%20about%20300%20charging%20stations%20already%20in%20the%20state,electric%20vehicles%20in%20Rhode%20Island.AMF Testimony List of Information and Data needed
[67] *See* https://afdc.energy.gov/evi-pro-lite

Figure 5.3.6: EVI-Pro Lite Inputs

Input	**2030**	**2040**	**2050**
Number of EVs	87300	675,000	840,000
Average daily miles traveled[68]	25	25	25
Average ambient temperature	Winter – 14degF Spring/Fall – 50degF Summer – 86degF	Winter – 14degF Spring/Fall – 50degF Summer – 86degF	Winter – 14degF Spring/Fall – 50degF Summer – 86degF
Percent vehicles that are all-electric	EV Dominant	EV Dominant	EV Dominant
Percent vehicles that are sedans	80% Sedans / 20% SUVs	80% Sedans / 20% SUVs	80% Sedans / 20% SUVs
Percent mix of workplace charging	50% Level 1 and Level 2 charging	20% Level 1 and 80% Level 2 charging	20% Level 1 and 80% Level 2 charging
Percent access to home charging	75% access	100% access	100% access
Percent mix of home charging	80% Level 1 and 20% Level 2 charging	20% Level 1 and 80% Level 2 charging	20% Level 1 and 80% Level 2 charging
Percent preference to home charging	100%	100%	100%
Home charging strategy	As fast as possible	As fast as possible	As fast as possible
Workplace charging strategy	As fast as possible	As fast as possible	As fast as possible

[68] Current Rhode Island information indicates daily miles driven are approximately 30 miles per day. However, daily miles are anticipated to decrease over time. 25 miles per day is the lowest setting.

Figure 5.3.7: 2030 Summer – Weekday and Weekend Load Cycle (Stacked Line)

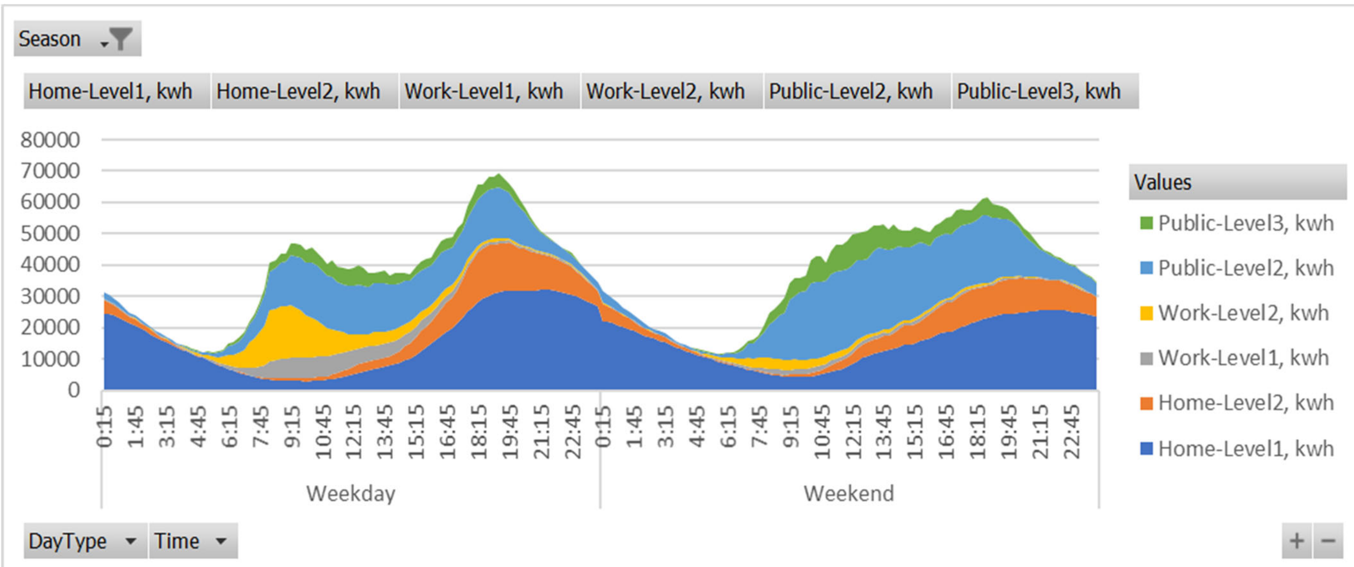


Figure 5.3.8: 2030 Spring/Fall – Weekday and Weekend Load Cycle (Stacked Line)

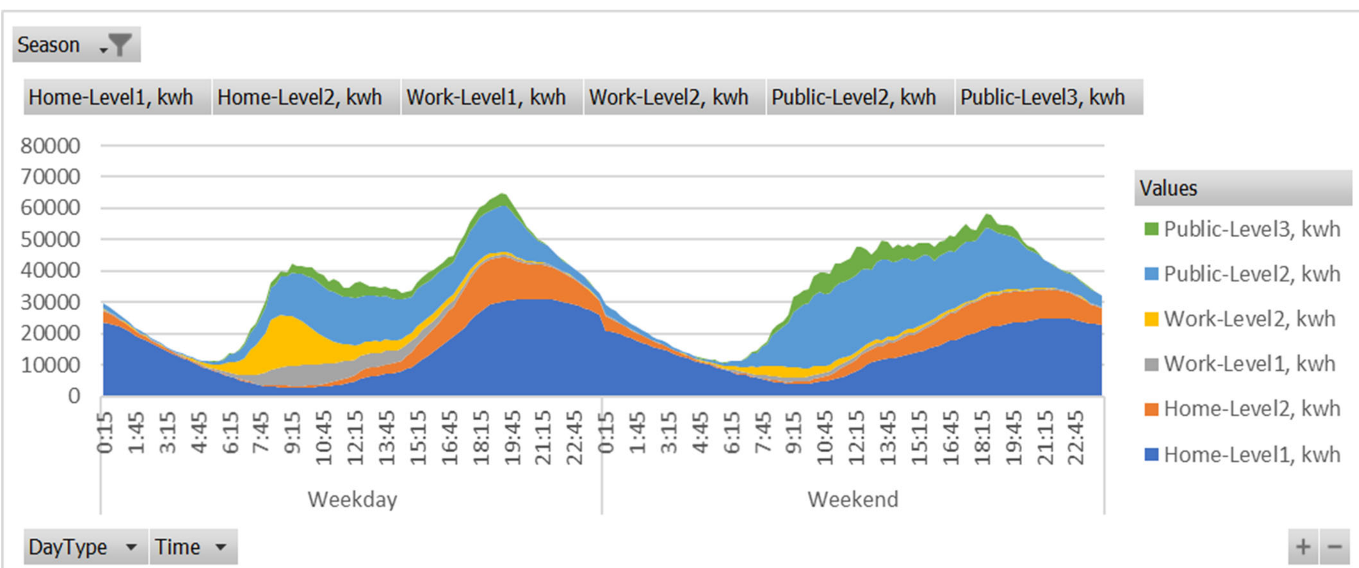
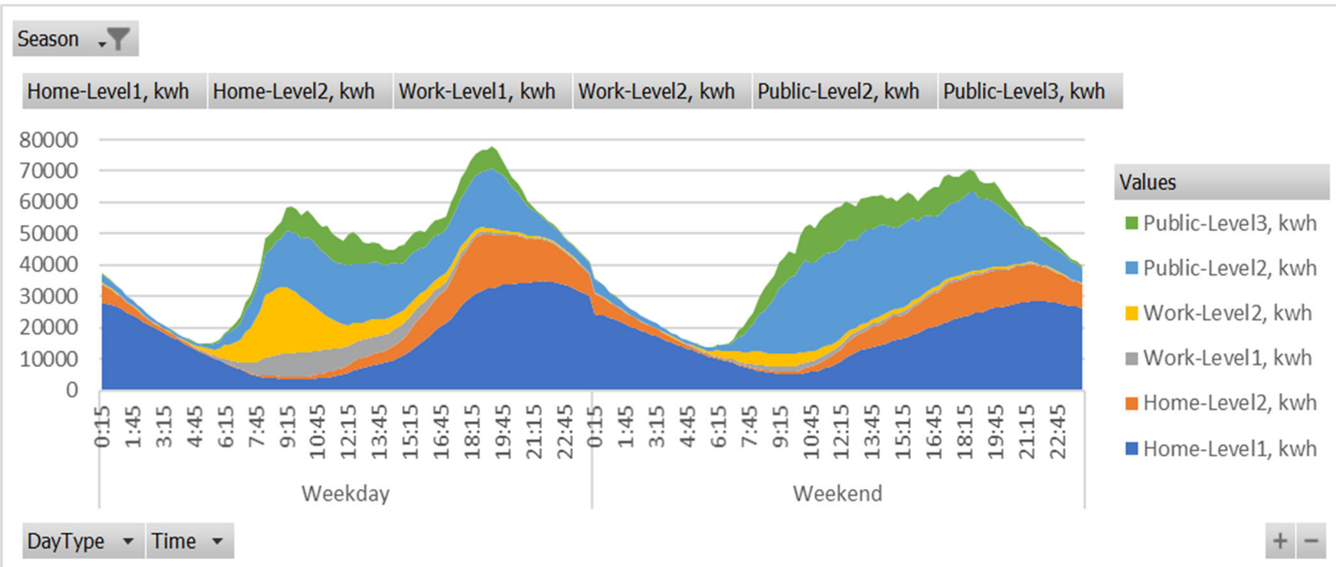
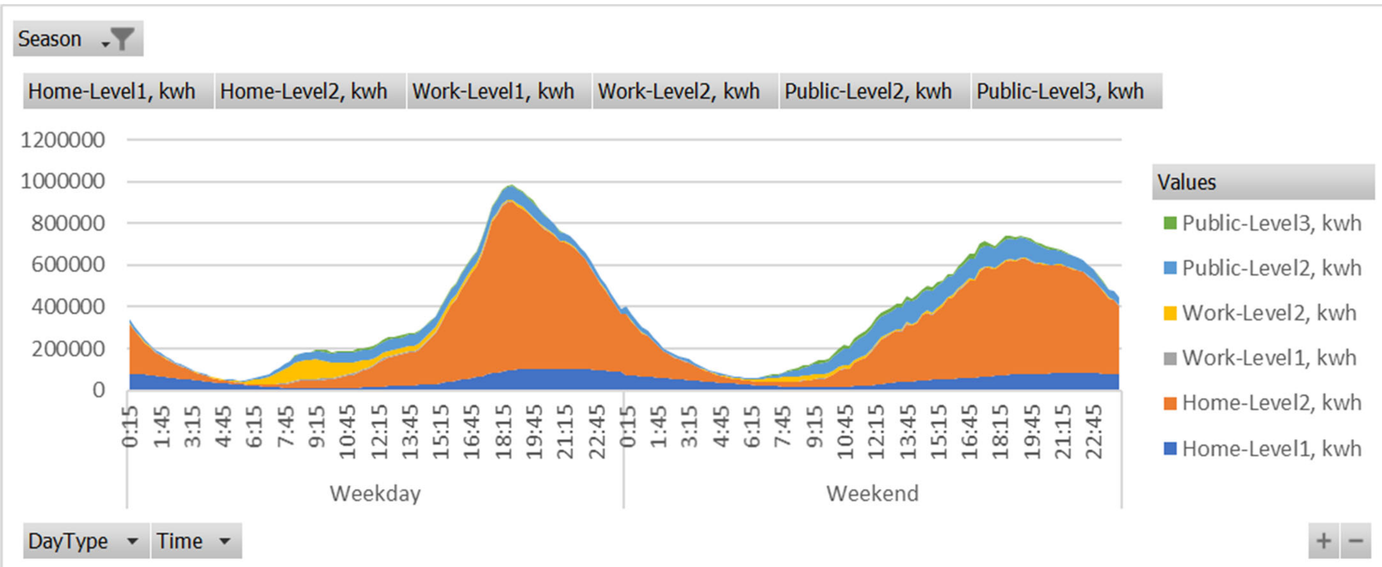


Figure 5.3.9: 2030 Winter – Weekday and Weekend Load Cycle



As can be seen from Figure 5.3.7 through 5.3.9, the ambient temperature affects battery performance increasing energy requirements during the summer and winter. The spring weekday peak is approximately 65,000 kilowatts, while the summer and winter weekday peaks are 70,000, and 79,000 kilowatts respectively. Using the 2030 winter peak as the worst case, each car contributes approximately 0.9 kilowatts to the peak period. Analysis of the 2040 and 2050 data shows that the peak contribution per car increase to 1.35 kilowatts for 2040 and 2050. Further, the charging behavior, set to "as fast as possible," results in a peak impact that coincides with the typical distribution circuit evening peak. Regardless of peak impacts, the 2030 charging schedule shows substantial energy usage aligned with solar generation hours. That alignment with generation diminishes as the number of EVs increase and charging power increases as shown in Figure 5.3.10.

Figure 5.3.10: 2050 Summer – Weekday and Weekend Load Cycle



The figure above represents approximately 840,000 vehicles in 2050. Home and workplace level 1 charging becomes minor. Although there is still some daytime energy that aligns with solar generation, the far magnitude of the energy is in the evening hours.

EV Charging Forecast Allocation to Network Model

To allocate the EV charging forecast to the distribution network for the 2030/40/50 study years, the approach used was to allocate EV vehicles to existing customer load points which represent residences within the CYME model. By 2030 it was assumed that 22% of residences would have one EV. By 2040, all residences are assumed to have one EV, with approximately 70% having 2 EVs. By 2050 it was assumed that 100% of the residences would have two EVs. By placing the EVs at existing customer sites, the best possible distribution is obtained aligned with home charging expectations. Furthermore, this method enabled the use of CYME application functionality to directly assign load cycle information to the modeled EV load.

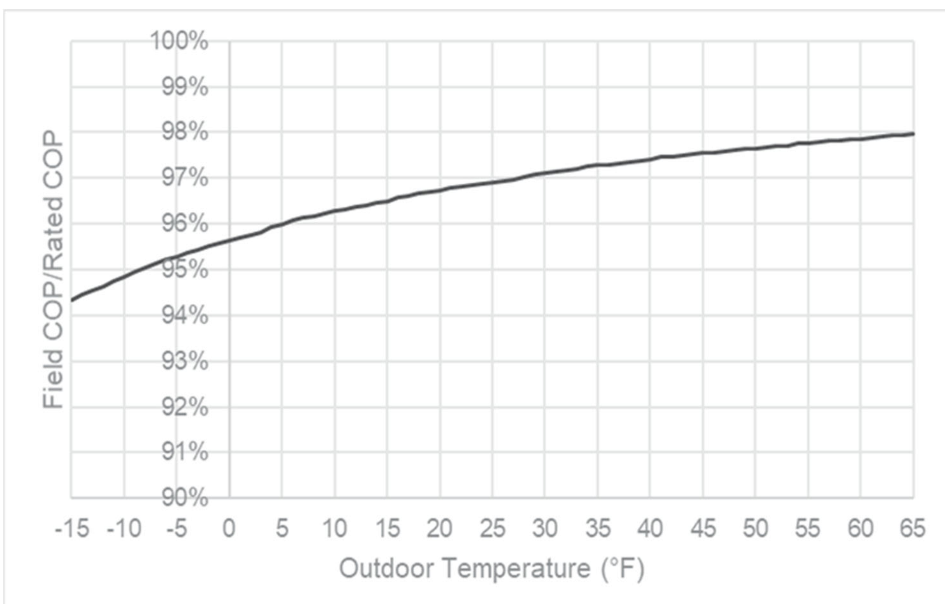
Electric Heat Pump Forecast

There are 4,000 to 6,000 homes heated with EHPs today while there are approximately 400,000 businesses and residences heating with gas/oil fuel. The number of homes/businesses converting from gas/oil to efficient EHPs for heating and air conditioning is projected to increase to 51,000 by 2030; 325,000 by 2040; and 400,000 by 2050.

The impact of this conversion will add significant peak demand and annual energy requirements to the Rhode Island Energy electrical distribution systems. It will also shift the annual peak demand on the system in a manner that will make the winter peak the highest peak demand of the year. Based on this conversion, the winter peak demand will increase by 220 MW in 2030; 1,310 by 2040 MW; and 2,825 MW by 2050. The EHP impact on the summer peak demand is projected to be trivial. This is because EHPs are expected to replace existing air conditioners, where the load increase is only the efficiency difference between the EHPs and older equipment. The overall conversion is expected to increase the annual energy requirements for Rhode Island by 2,200 Gwh.

To develop the EHP load cycle, a custom-built model was developed. The model uses a 2015 temperature cycle as an extreme winter peak case with average heating energy. Inputs include daytime and nighttime turn on temperatures, backup heating assumptions (resistive heat), improvements in building efficiency, and adjustable coefficient of performance ("COP") based on ambient temperature. Figure 5.3.11 shows the impact of temperature on the COP.

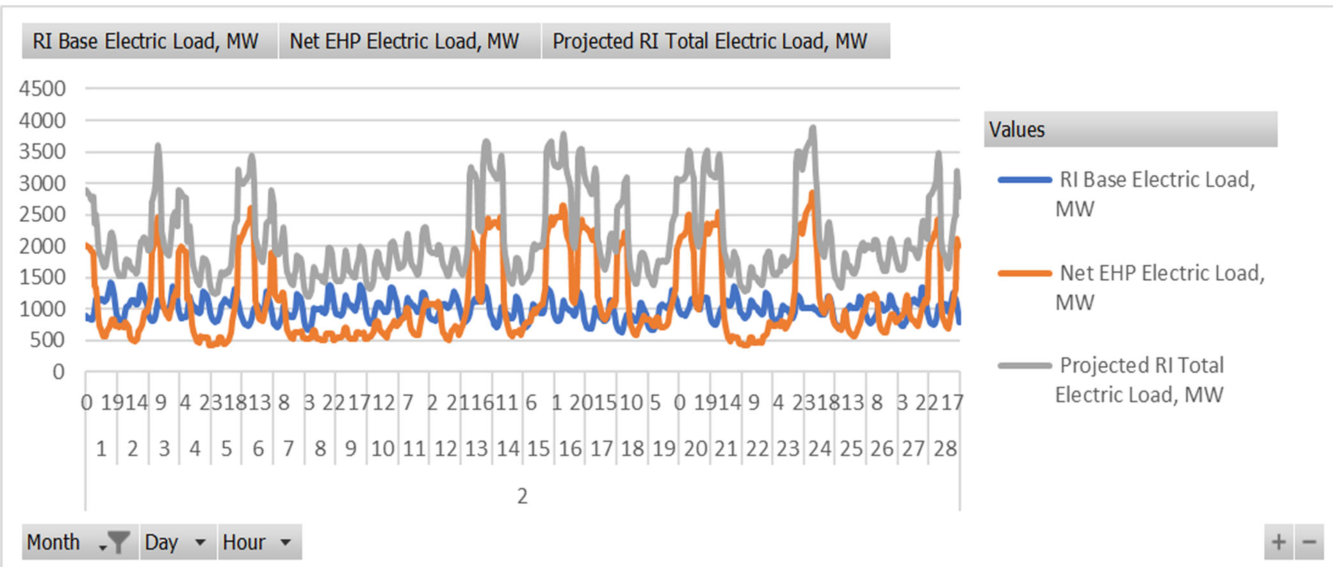
Figure 5.3.11: Impact of Temperature on Heat Pump Coefficient of Performance[69]



[69] *See* https://ma-eeac.org/wp-content/uploads/MA19R16-B-EO_Energy-Optimization-Measures-and-Assumptions-Update-Memo_Final_2020-03-02-1.pdf

Figure 5.3.12 shows the month of February, as an example, demonstrating the resulting EHP load cycle (orange line) and its resulting impact to total Rhode Island load (gray line). As can be seen from the graph, heating loading can result in a peak over 3700 megawatts for Rhode Island. The increased loads are driven by the coldest days, which include substantial resistive heat that occurs early morning and late evening when thermostat adjustments are typically made.

Figure 5.3.12: Impact of Temperature on Heat Pump Coefficient of Performance



Electric Heat Pump Forecast Allocation to Network Model

To allocate the EHP forecast to the distribution network for the 2030/40/50 study years, the approach used was to allocate the addition EHP demand to each customer residence. By 2030 approximately 13% of the Rhode Island homes can be converted to EHPs, increasing to 80 percent in 2040, and to 100 percent by 2050. By placing the EHPs at existing customer sites, the best possible distribution is obtained and aligned with home heating expectations. Furthermore, this method enabled the use of CYME application functionality to directly assign load cycle information directly to the modeled EHP load.

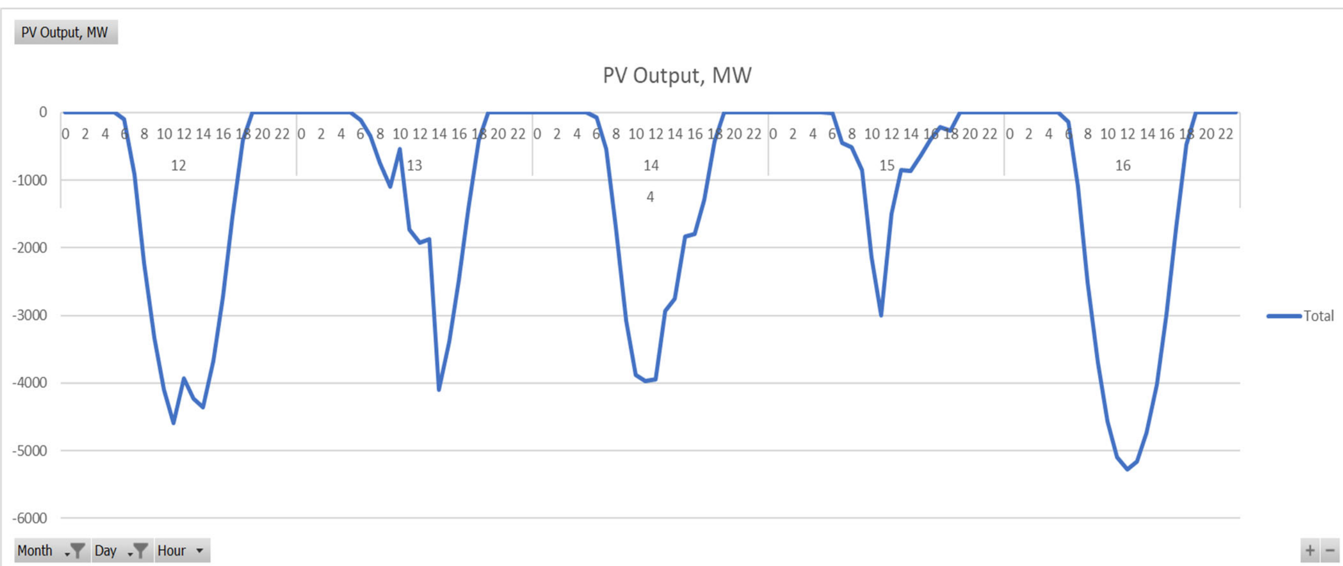
It is significant to note that the amount of solar PV forecast to meet the Climate Mandates by 2050 is 5,000 MW nameplate capacity, which exceeds the expected peak demand during the summer peak – 2,785 MW in 2050. In addition, the winter peak demand in 2050 is essentially double what it is today because of the demand increases created by the EHP load and EV charging. This will double the loading on the T/D system requiring significant upgrades to meet the load and keep the lights on.

Solar PV Forecast

Today there is about 504 MW (DC nameplate capacity) of solar PV connected to the Rhode Island Energy electric distribution system and over 600 MW in the interconnection queue. This existing PV provides an annual energy supply to Rhode Island of approximately 618,000 MWh. To meet the state's Climate Mandates, the PV nameplate capacity in the Distribution Study was forecasted to be a total of 1,800 MW by 2030; 3,700 MW by 2040; and 5,300 MW by 2050.

The National Renewable Energy Lab's ("NREL") PVWatts Calculator[70] was used to develop the solar generation cycle. This online calculator uses solar radiation data to estimate hour-by-hour PV data. The resulting generation cycle provides suitable test points that represent full solar output and potentially cloud covered periods as shown in Figure 5.3.13.

Figure 5.3.13: Example 5 Day Sample - PVWatts Generation Cycle



Solar PV Allocation to Network Model

To allocate the forecasted Solar PV to the distribution network for the 2030/40/50 study years, the total solar generation determined by the emission analysis was assigned to the distribution feeder based upon its load. In other words, the generation was allocated to the load as closely as possible. In this manner, the analysis is not influenced by large locational differences between generation and load that could

[70] *See* https://pvwatts.nrel.gov/

skew infrastructure requirements. Instead, as intended, the analysis could focus on the time disparity between the generation and load cycles. Once the generation was allocated by feeder, it was spread randomly across the circuit topology in relatively small sizes. This ensured the analysis and infrastructure requirements were not influenced by large clusters of generation. Although this contrasts with the real-world conditions where large DER sites are interconnected, this allocation method was chosen to be conservative in nature, representing a best-case outcome.

It is significant to note that the amount of solar PV forecast to meet the Climate Mandates by 2050 is 5,000 MW nameplate capacity, which exceeds the expected peak demand during the summer peak in 2050.

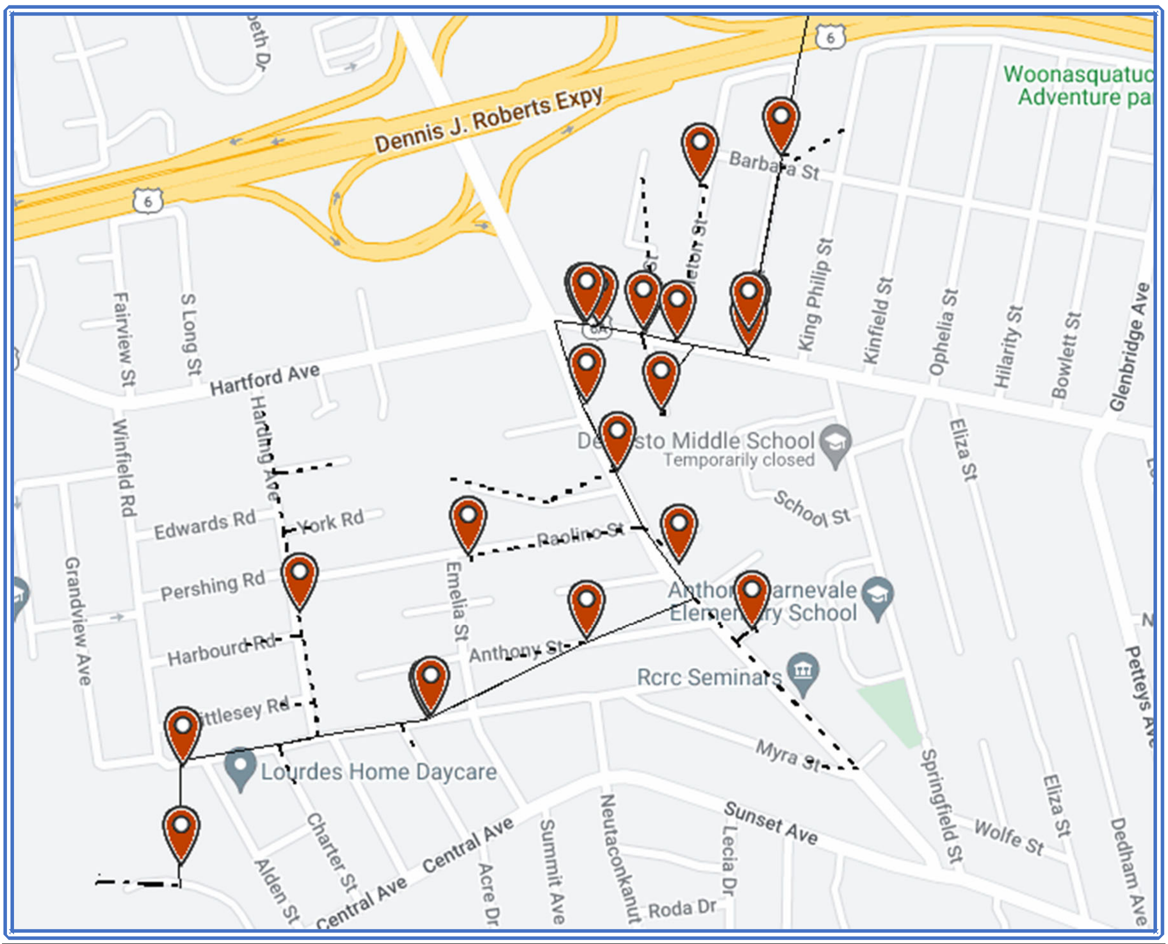
Figure 5.3.14 provides an example of the PV allocation by feeder. This example also illustrates a manual allocation of some PV to the supply line. Although the supply lines may not serve load directly, they typically have relatively high capacity that may be suitable for generation interconnection as demonstrated by recent interconnection applications. This manual effort was designed to make maximum use of that capacity.

Figure 5.3.14: Example PV Allocation – Johnston Substation

Substation	Feeder or Supply Line	Allocated MW PV 2030	Allocated MW PV 2040	Allocated MW PV 2050	2040 Manual DG Allocation	2050 Manual DG Allocation
JOHNSTON	18F10	3.66	8.42	12.43	-	-
JOHNSTON	18F11	0.00	3.66	7.47	-	-
JOHNSTON	18F12	1.53	3.48	5.11	-	-
JOHNSTON	18F13	3.22	7.49	11.09	-	-
JOHNSTON	18F14	1.62	3.68	5.42	-	-
JOHNSTON	18F5	3.47	8.50	12.73	-	-
JOHNSTON	18F6	0.00	1.81	5.06	-	-
JOHNSTON	18F7	3.06	7.45	11.16	-	-
JOHNSTON	18F8	1.83	5.09	7.84	-	-
JOHNSTON	18F9	3.49	8.37	12.47	-	-
JOHNSTON	2202	0.00	0.00	0.00	-	-
JOHNSTON	2211	10.26	23.25	34.19	2.00	10.00
JOHNSTON	2226	0.00	0.00	0.00	-	-
JOHNSTON	2227	7.78	17.64	25.94	2.00	10.00
JOHNSTON	2228	5.35	12.13	17.83	2.00	10.00

Figure 5.3.15 illustrates the distributed method to allocate the generation within the model.

Figure 5.3.15: Example Model Distribution of PV – Portion of 18F5 Feeder

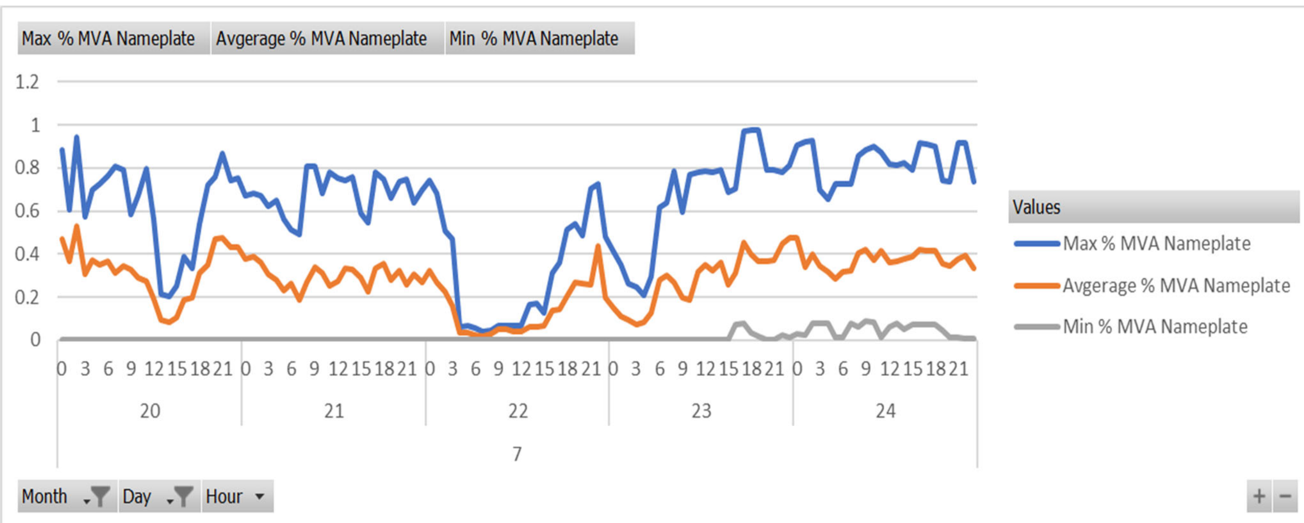


Wind Forecast

Today there is approximately 50 MW of onshore wind and 30 MW of offshore wind in Rhode Island. There is an offshore wind farm pending interconnection with 400 MW allocated to Rhode Island. The existing wind generation provides an annual energy supply to Rhode Island of approximately 165,000 MWh. To meet the State's Climate Mandates, the onshore and offshore wind will need to respectively increase to 100/900 MW by 2030; 115/1,035 MW by 2040; and 145/1,300 MW by 2050.

The wind generation cycle was developed using existing data. The resulting generation cycle results in substantial variability as shown in Figure 5.3.16. The figure shows the maximum, minimum, and average across a sample 5-day period which includes the typical summer peak day. It is preferable to have the minimum and maximum line as close as possible, which would indicate a dependable source. In this case, the graph shows that for most hours, the generation output ranges between 0 and nameplate rating.

Figure 5.3.16: Example 5 Day Sample - Wind Generation Cycle



Wind Allocation to Network Model

The forecasted onshore wind generation was manually added to the distribution supply lines. This was done because of the relatively small onshore wind volume as compared to solar generation and the higher capacity of the supply lines. The offshore wind generation was included in the transmission model.

Design and Performance Criteria

The studies were conducted following approved Rhode Island Energy sub-transmission and distribution planning procedures. Design for upgrades and new facilities followed best practices for feeder design, transformer sizing, substation design, etc. The performance criteria used was based on identifying thermal and voltage violations on the electric system:

1. Voltages below 95% or above 105% of nominal voltage
2. Thermal loading on equipment exceeding its ratings

8,760-Hour Load Flow Analysis

Hourly (i.e., 8760 hours/year) demand forecasts were created for each DER type and added to the Rhode Island "base load" to assess the distribution system impacts. These hourly forecasts were used in a "top-down" assessment of aggregated net load duration curves for Rhode Island to identify potential impacts and opportunities at a macro level, and a "bottom-up" assessment using detailed feeder-level load flow models to identify the emergence of local constraints. The 8760-hour three-phase load flow analysis applied the long-range forecast to all hours in a year through the three test years to all Rhode Island Energy feeders. This approach was done to determine the worst-case hours when system violations occurred. The CYME three-phase load flow study tool was used to model the network to determine the hours that most likely would result in criteria violations (i.e., high or low voltage, or thermal overloads).

After identifying issues for each study year, two alternatives were analyzed to determine what T/D upgrades were the lowest cost solutions to mitigate the issues. These two alternatives were:

1. **No Grid Modernization Alternative** – In this case only traditional transmission and distribution investments were selected to mitigate the thermal loading and voltage violations identified. In other words, investments for automation, situational awareness, and control were not available to identify and mitigate criteria violations. Only traditional solutions such as phase balancing, re-conductoring feeders, new feeder circuits with new substation bays, new transformers, new T/D substations, reconductoring sub-transmission lines, new sub-transmission lines with new substation bays, and traditional reclosers, capacitor banks, and voltage regulators, were considered. Note that storage batteries could not be deployed as solutions in this alternative because of the lack of situational awareness and monitoring and control functionality, which are only available through grid modernization solutions.
2. **Grid Modernization Alternative** – Grid Modernization technologies were available in all three study years – 2030, 2040, and 2050. This included state-of-the-art ADMS/SCADA functionality including FLISR, VVO/CVR, TVR/CPP and locational Demand Response, and DERMS with DER Monitor/Manage; secure communications; AMF meters, and GMP Advanced Field Devices (e.g., advanced reclosers, smart capacitors and regulators, microprocessor relays, and DER Monitor/Manage equipment). Then the required traditional investments were added to mitigate the violations identified. This alternative was chosen to determine if grid modernization could eliminate or defer traditional transmission and distribution investments and if so, by how much.

The detailed study steps are as follows:

Distribution Study Steps

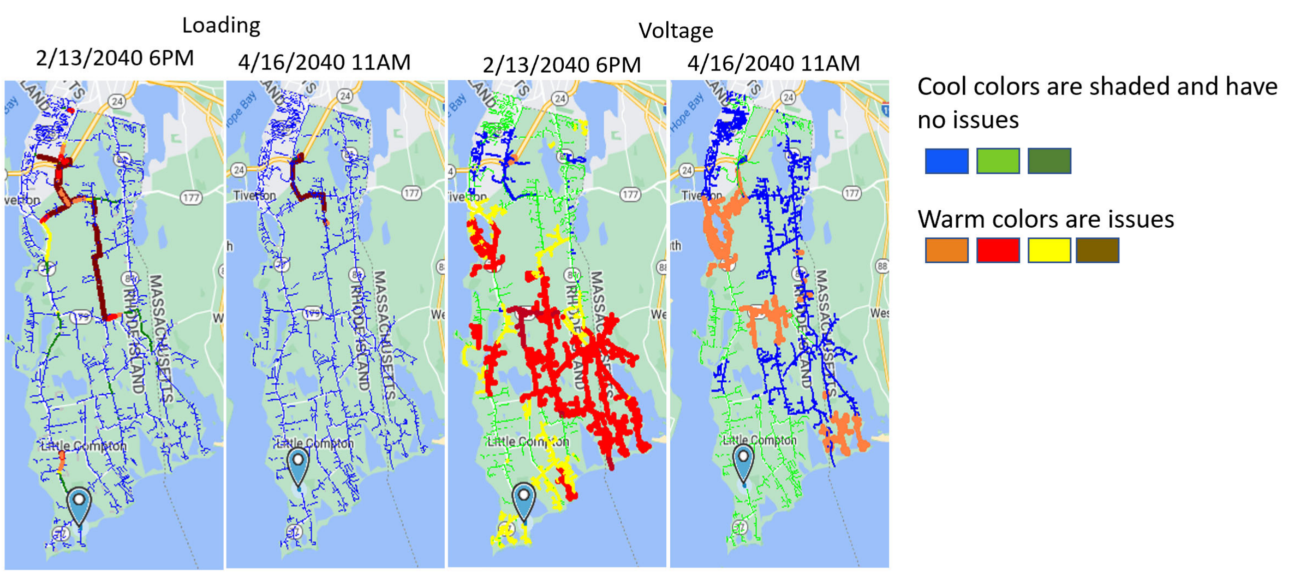
1. Verify generation allocation.
    a. PV
        i. Limited to 5MW per 5kV feeders.
        ii. Limited to 15MW per 15kV feeders.
        iii. Limited to 40MW on 25kV feeders.
        iv. Limited to 60MW on 35kV feeders.
    b. Check manual allocation to supply lines
        i. 2040 manual PV placed as 2MW sites at midpoints of circuits.
        ii. 2050 manual PV placed as 5MW sites at 1/3 and 2/3 the length of the circuits.
        iii. Onshore wind was manually assigned to sub-transmission lines and feeders.
            1. 2030 wind placed as 3.5MW sites at midpoints of circuits.
            2. 2040 and 2050 wind was placed as 5MW sites at 1/3 the length of the circuits.
2. Verify EV allocations
    a. Each EV added as 1.347kW load based on EVI-Pro load cycle analysis.
    b. Limited to 2 EV loads per customer.
3. Verify EHP allocations.
    a. Each HP added as blended 7kW per EHP based on EHP load cycle analysis.
    b. Limited to 1 blended EHP load per customer.
4. Import normalized 8760 profiles for:
    a. residential/commercial – normal and 3% energy shift.
    b. EV – normal and 3%, 5%, 10%, 25%, 50% energy shifts.
    c. HP - normal and 3% energy shift.
    d. PV – normal and curtailed.
    e. Onshore wind – normal and curtailed.
    f. Offshore wind – normal and curtailed.
5. Run 8760 load flow with profile analysis for 2030, 2040, and 2050.
    a. Tested 1, 2, and 3-hour intervals. Data limits, software limits, and processing time required 3-hour time intervals.
    b. Data export limited by equipment type and assigned variables.
6. Identify worst case dates and times for each feeder in 2030, 2040, 2050 using monitor reports and network summaries.
    a. High-load, low-generation dates and times identified by largest forward peak powers at feeder heads.
        i. 2030 forward peak time identified at 7/22/30 6PM.
        ii. 2040 forward peak times identified at 2/13/40 6PM, 2/24/40 6AM, and 7/22/40 6PM.

            iii. 2050 forward peak times identified at 2/13/50 6PM, 2/24/50 6AM, and 7/22/50 6PM.
    b. High-generation, low-load dates and times identified by largest reverse peak powers at feeder heads.
        i. 2030 reverse peak times identified at 4/16/30 12PM and 5/25/30 12PM.
        ii. 2040 reverse peak times identified at 4/16/40 12PM, 5/25/40 12PM, and 4/6/40 12PM.
        iii. 2050 reverse peak times identified at 4/16/40 12PM, 5/25/50 12PM, and 4/6/50 12PM.
7. Reviewed logs for non-convergence and current model as necessary.
8. Run single time load flows at worst case dates and times in 2030, 2040 and 2050 to identify issues.
    a. Overload and over/undervoltage abnormal conditions were highlighted in CYME.
9. Reconfigure system as necessary and observe modeled area study infrastructure performance.
10. Create non-GM fixes to address issues for the worst-case dates and times in 2030, 2040 and 2050 with traditional solutions.
    a. Prioritized solution set:
        i. Balancing and load transfers
        ii. Capacitors and regulators – advanced but autonomous control
        iii. Reclosers - advanced but autonomous control
        iv. Reconductoring
        v. Line extensions
        vi. Substation expansion and new feeders established
        vii. New substations established
    b. Rechecked area study recommendations for obsolescence or alignment with the No Grid Modernization alternative
    c. Created cost estimate of non-GM fixes.
11. Create GM fixes to address issues for the worst-case dates and times in 2030, 2040 and 2050 with grid modernization solutions
    a. Prioritized solution set:
        i. Apply energy shifting load cycles
        ii. Apply curtailment generation cycles
        iii. Balancing and load transfers
        iv. Capacitors and regulators – advanced and centralized control
        v. Reclosers - advanced and centralized control
        vi. Reconductoring
        vii. Line extensions
        viii. Substation expansion and new feeders established
        ix. New substations established
        x. Energy storage considered and steps vi through ix revaluated

   b. Rechecked area study recommendations for obsolescence or alignment with Grid Modernization alternative.
   c. Created cost estimate of GM fixes.
12. Rerun 8760 3-hour increment analysis for the No-Grid Modernization and Grid Modernization alternatives
   a. Check no remaining abnormal conditions
   b. Compare energy, kw, and kvar values
      i. Use energy difference for VVO and loss analysis
      ii. Use monitor outputs for VVO profiles
   c. Check load and generation energy values
   d. Relocate reclosers as necessary

Figure 5.3.17 illustrates the types of issues that were identified in the Tiverton area in the 2040 model year. Attachments F and M demonstrate details of the analysis. Attachment F shows the circuit diagrams after issue identification and after solution modeling. Specifically, Attachment M illustrates the No Grid Modernization alternative and Grid Modernization alternative details on determining specific infrastructure.

Figure 5.3.17: Grid Modernization Tiverton Area Results 2040



Section 5.5 summarizes the extent and cost of the upgrades required for the No Grid Modernization alternative for each of the 11 Study Areas. This solution is being shown for illustrative and cost/benefit comparison purposes only. A transmission and distribution system with this level of DER penetration, variable load conditions, etc., could not be safely and reliably operated without visibility and situational awareness of real-time conditions.

Grid Modernization Alternative

The Grid Modernization alternative provides visibility, situational awareness, and control of the distribution system by the distribution system operator and to automated operational systems provided by grid modernization functionality and equipment. The solution identifies a reduced number of new or reconductored lines, transformers, substations, and voltage regulating equipment necessary to obviate the thermal and voltage violations identified for each study year. The number of upgrades is greatly reduced as compared to the No Grid Modernization alternative due to the functionality of grid modernization, which allows sectionalizing, load transfer, demand shifting, TVR/CVR, VVO, FLISR, Demand Response and other key features. Since grid modernization functionality and equipment is in the solution, the amount of DER that must be curtailed during the year is greatly reduced by the DER Monitor/Manage functionality provided by ADMS - DERMS. This allows surgical curtailment of DER in small increments when and where needed to avoid violations. Furthermore, grid modernization enables dispatch of the DER generation down or up with the DERMS system to avoid voltage or thermal violations on the system during the varying conditions of each day. For example, during a sunny summer day, the grid modernization functionality will be utilized to control all available voltage regulating equipment and controls to take off capacitors, use voltage regulators and tap changers with grid modernization controls to reduce voltage, and then use the DER inverters to reduce voltage. Later in the same day when sunlight dissipates and the solar generation ramps down, the grid modernization voltage regulating equipment and controls adjust the voltage to the acceptable range. This use of grid modernization equipment and controls can reduce the amount of DER curtailment during the year. Section 5.6 summarizes the extent and cost of the upgrades required for the Grid Modernization alternative for each of the 11 Study Areas.

In the Grid Modernization alternative, grid modernization technology was used to shift energy from peak hours to off-peak hours in the following manner:

1) Time Varying Rates and the AMF and grid modernization functionality were used to shift:
   a. 3% of the residential/commercial load profile to high generation hours
   b. 25% of the EV charge energy load profile to high generation hours
   c. 3% of the EHP load profile to high generation hours
2) ADMS/DERMS/DER Monitor/Manage functionality were used to reduce Solar PV generation by 3% during the worst-case hours to mitigate criteria violations

New 2030/40/50 cases were then executed to determine the remaining violations for the Grid Modernization alternative.

5.4 Comparison with National Grid Approach – Prior GMP Filing

There are several differences in the approach used in the Rhode Island Energy GMP as opposed to the National Grid GMP filing in January 2021 as summarized below.

1. The National Grid analysis was made for only 6 feeders on the distribution system and the results were then extrapolated. The Rhode Island Energy GMP evaluated all 400 distribution feeders and all 56 sub-transmission lines over the Distribution Study period.
2. The Rhode Island Energy Distribution Study was expanded to include a Transmission Study which then analyzed impacts on the Rhode Island Energy bulk electric system.
3. The avoided cost for infrastructure upgrades in the Rhode Island Energy Distribution Study were based on actual distribution simulation studies as opposed to the use of typical percentage factors in the National Grid filing.
4. The Rhode Island Energy Distribution Study considered the application of storage batteries as a grid modernization technology solution in the GMP.

Rhode Island Energy had the benefit of building upon the initial studies performed by National Grid to enhance the approach that was originally taken to moving from extrapolation to one that is specific to the distribution and transmission infrastructure in the State. Because of the comprehensive nature of the Distribution and Transmission Studies that Rhode Island Energy performed for the GMP, the results are more accurate and the Area Plans are specifically linked to the long-range vision. The Rhode Island Energy approach bolsters confidence in the recommendations and improves decision making as it relates to future infrastructure additions because incremental additions are now more likely to be congruent with the ultimate system design requirements that will achieve the Climate Mandates. An expanded discussion of the differences in the approach for GMP between National Grid and Rhode Island Energy can be found in Attachment E.

5.5 Sub-Transmission and Distribution Infrastructure Results

Each alternative mitigated the criteria violations that were identified for the 2030/40/50 study years. However, the cost and performance benefits are significantly different.

No Grid Modernization Alternative

This alternative resulted in significant DER curtailment and significant cost – see Figure 5.4 below:

Figure 5.4: No Grid Modernization T/D Infrastructure Costs -- 2050

	Area	New D-Feeder, mi.	Re-conductored D Feeder, mi.	New Feeder Positions	New Distribution Substations	New Sub-Transmission Lines, mi.	Costs Nominal ($M)
1	BVN	29.5	9.8	15	2	2.3	275
2	BVS	35.1	11.7	30	2	2.8	383
3	CRIE	37.4	12.5	21	3	2.9	371
4	CRIW	40	17	17	3	12	511
5	EB	7	7.1	11	2	5	145
6	NCRI	55.3	67.7	20	2	0	626
7	Newport	40.4	13.5	23	3	3.2	406
8	Providence	40.7	13.6	52	4	3.2	574
9	SCE	31.3	43.3	13	3	0	385
10	SCW	16.1	3.4	5	1	0	96
11	Tiverton	16.8	15.2	5	1	1.9	128
	Total	349.6	214.8	212	26	33.3	3900

Grid Modernization Alternative

This alternative resulted in significantly lower transmission and distribution costs as shown in Figure 5.5 below. Because grid modernization functionality was available to provide visibility and situational awareness to the distribution system operators in real-time and provided the technology and equipment to reduce the peak demand during peak demand periods and minimize backflow conditions during all hours, the amount of T/D investment by 2050 is significantly less than in the No Grid Modernization alternative.

Figure 5.5: Grid Modernization T/D Infrastructure Costs -- 2050

	Area	New D-Feeder, mi.	Re-conductored D Feeder, mi.	New Feeder Positions	New Distribution Substations	New Sub-Transmission Lines, mi.	Costs Nominal ($M)
1	BVN	14.1	9.4	6	1	0	194
2	BVS	16.9	11.2	12	1	0	255
3	CRIE	17.9	12	9	1	0	256
4	CRIW	12.9	17	9	1	0	271
5	EB	2.5	16.5	4	0	0	116
6	NCRI	40.6	69.6	14	2	0	443
7	Newport	19.4	12.9	10	1	0	231
8	Providence	19.5	13	21	2	0	423
9	SCE	0	19.5	0	1	0	287
10	SCW	3.4	0	0	1	0	55
11	Tiverton	2.2	7.7	2	0	0	59
	Total	149.4	188.8	87	11	0	2590

5.6 Avoided Transmission and Distribution Cost Summary with Grid Modernization Alternative

Figure 5.6 below summarizes the avoided transmission and distribution cost savings due to the Grid Modernization alternative through the 2050 study year. The 2030/40/50 study projects these savings for each year, however, the BCA in Section 8 only considers these savings through 2041 as it is a 20-year NPV analysis. Attachment F provides details comparing Grid Modernization alternative to No Grid Modernization alternative for each Planning Area in 2040, to be consistent with the BCA analysis.

Figure 5.6: Avoided T/D Infrastructure Costs -- 2050							
	Area	**New D-Feeder, mi.**	**Re-conductored D Feeder, mi.**	**New Feeder Positions**	**New Distribution Substations**	**New Sub-Transmission Lines, mi.**	**Costs Nominal ($M)**
1	BVN	15.4	0.4	7	1	2.3	81
2	BVS	18.3	0.5	18	1	2.8	127
3	CRIE	19.5	0.5	12	2	2.9	115
4	CRIW	27	0	9	2	12	241
5	EB	4.5	-9.4	7	2	5	30
6	NCRI	14.7	-1.9	6	0	0	183
7	Newport	21	0.6	13	2	3.2	175
8	Providence	21.2	0.6	31	2	3.2	151
9	SCE	31.3	23.8	13	2	0	98
10	SCW	16.1	0	4	0	0	41
11	Tiverton	14.6	7.5	3	1	1.9	69
	Total	203.6	22.6	122	15	33.3	1311

The study identified that the Grid Modernization alternative provides substantial reduction of infrastructure versus the No Grid Modernization alternative. Regardless of the specific location and size of the PV, wind generation, EV, and EHP, the Grid Modernization alternative provides superior adaptability and agility to all the possible future Climate Mandates scenarios. The associated costs and benefits are described in detail in Section 8.0.

5.7 DER Curtailment Summary

There are two important aspects to providing a reliable power system when interconnecting load to generation: 1) the capacity to transmit and distribute energy from generation to load must be sufficient; and 2) the load-to-generation balance must be maintained all of the time. The capacity to transmit and distribute energy was thoroughly explored in the Distribution Study described above. Analysis to maintain the load-to-generation balance is described in this section.

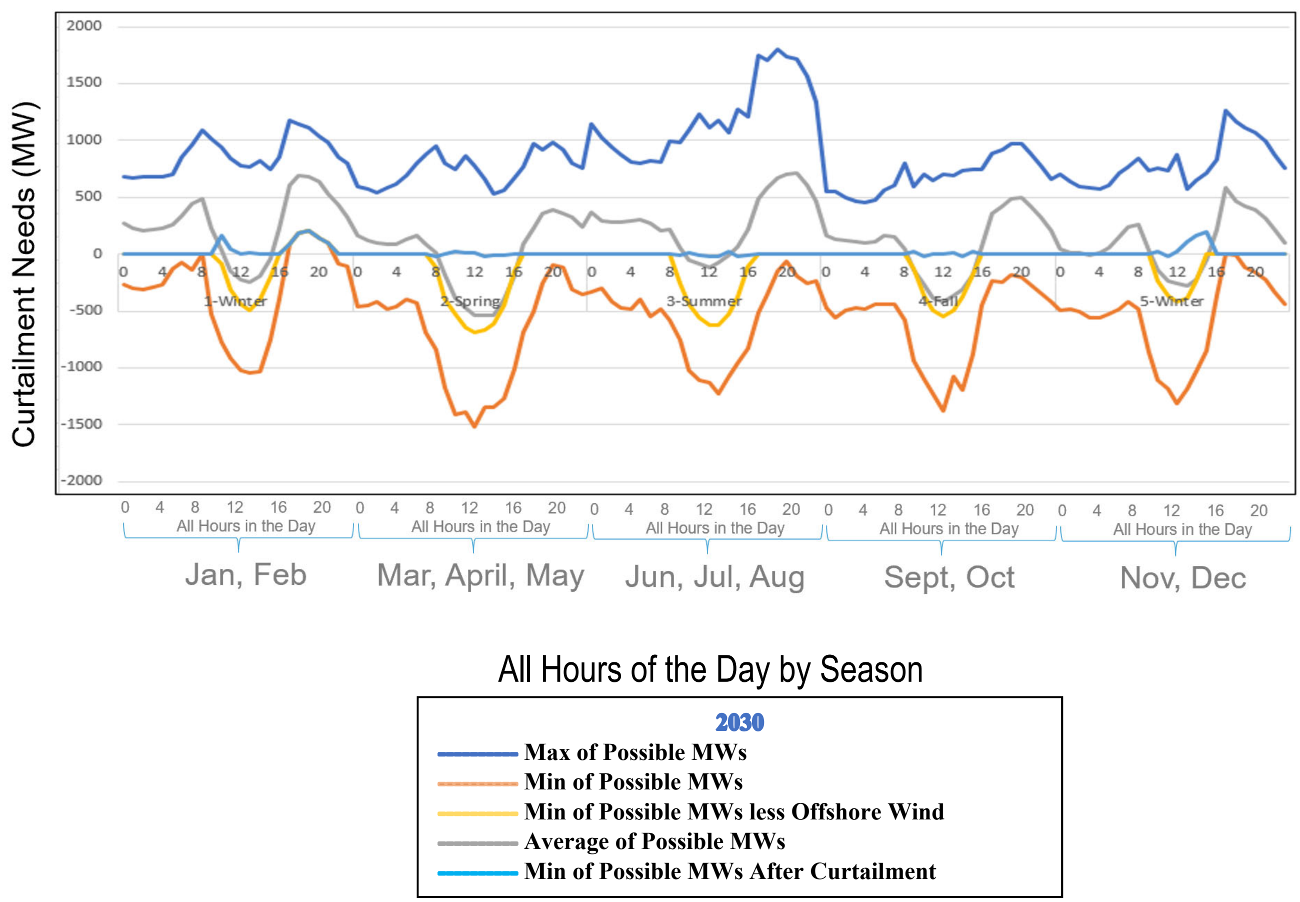
Without grid modernization investments, electric distribution system issues because of excess DG generation cannot be monitored or managed (i.e., curtailed) in a granular manner. The case considering the No Grid Modernization alternative assumes curtailment of renewable DG anytime the estimated maximum seasonal DG output of the installed capacity is predicted to exceed the design limitations of the system, which in this case is the estimated seasonal minimum load for the State. This “seasonal curtailment” results in an average renewable DG curtailment of 17.7% of its annual energy output by 2030 and increases in subsequent years.

Because the Grid Modernization alternative provides distribution system operators with visibility, situational awareness, and system management capabilities, DER curtailment can be minimized to 3% annually to maintain a balance of load-to-generation and the curtailment can be performed to the extent that it is needed on a feeder specific basis. System management to achieved reduced curtailment using the Grid Modernization alternative comes from the ADMS functionality for TVR, VVO, and DERMS with DER Monitor/Manage, and Advanced capacitors and regulators. In the early years of grid modernization deployment, curtailment will be accomplished by the advanced reclosers at the commercial solar PV sites. As additional solar PV is installed with the DER Monitor/Manage and ADMS – DERMS software, the amount of DER that needs to be curtailed due to thermal and voltage issues on the system will be greatly reduced.

The DER Monitor/Manage functionality that used to manage the solar PV curtailment described above is also planned for Battery Energy Storage System (“BESS”) inverter management. With the addition of BESS as a solution in the Grid Modernization alternative, the annual DER energy curtailment requirement is reduced from 17.7% to 0.7%. The BESS management solution has been quantified in the BCA for the Grid Modernization alternative, contributing significantly to avoided infrastructure cost and the achievement of the Climate Mandates.

Figure 5.7 shows the seasonal curtailment needs. The chart illustrates the maximum, minimum, and average possible megawatts across the hours of a day for each season in 2030. For example, in the first winter period (January to February) at noon, the system can vary between +750 megawatts and -1000 megawatts. Without offshore wind, the system can vary to approximately -500 megawatts. ISO-NE will dispatch the offshore wind on the bulk electric system. Since it is a control area resource based on reliability and market needs, it does not affect this analysis. With ISO-NE controlled resources excluded, the distribution system curtailment is determined by the minimum megawatts less offshore wind (yellow line). To maintain a load-to-generation balance, the yellow line must be curtailed to zero resulting in the light blue line. The distributed generation would be reduced by 500 MW at the noon hour in the winter regardless of actual system conditions. This is because with the No Grid Modernization alternative, there is no sensing and data to determine the various weather conditions and generation characteristics across the winter days, and therefore there is no ability for the Distribution Control Center to receive real-time data or take real-time action. As a result, the curtailment must be set for the worst case across the hours of each season.

Figure 5.7: Seasonal DER Curtailment Needs (MW) in 2030: Maximum, Minimum, and Average across All Hours of a Day by Season



With the sensing, data, and remote control provided by capabilities from the Grid Modernization alternative, a much more granular dispatch can be provided that minimizes the curtailment requirement where it is only called upon when and where it is necessary to maintain load-to-generation balance.

Figure 5.8, Figure 5.9 and Figure 5.10 below present a comparison of curtailment requirements for the Distribution Study alternatives where curtailment needs are shown by season, month and day-of-month or hour of the day. Figure 5.8 shows the DER curtailment needed to balance load-to generation by season in 2030 in megawatt*hours (MWh) for the No Grid Modernization alternative. This compares to Figure 5.9, which shows the DER curtailment needed to balance load-to-generation by season in 2030 in megawatt*hours (MWh) for the Grid Modernization alternative. Figure 5.10 adds energy shifting to the Grid Modernization alternative capability shown in Figure 5.9 to further reduce DER curtailment requirements. If BESS management is applied to conditions in Figure 5.10, which includes Grid Moderation alternative with energy shifting, the curtailment requirement is reduced to less than 1% in this particular case.

Figure 5.8: 2030 Daily Curtailment Across Seasons
In the No Grid Modernization Alternative (MWh / day)

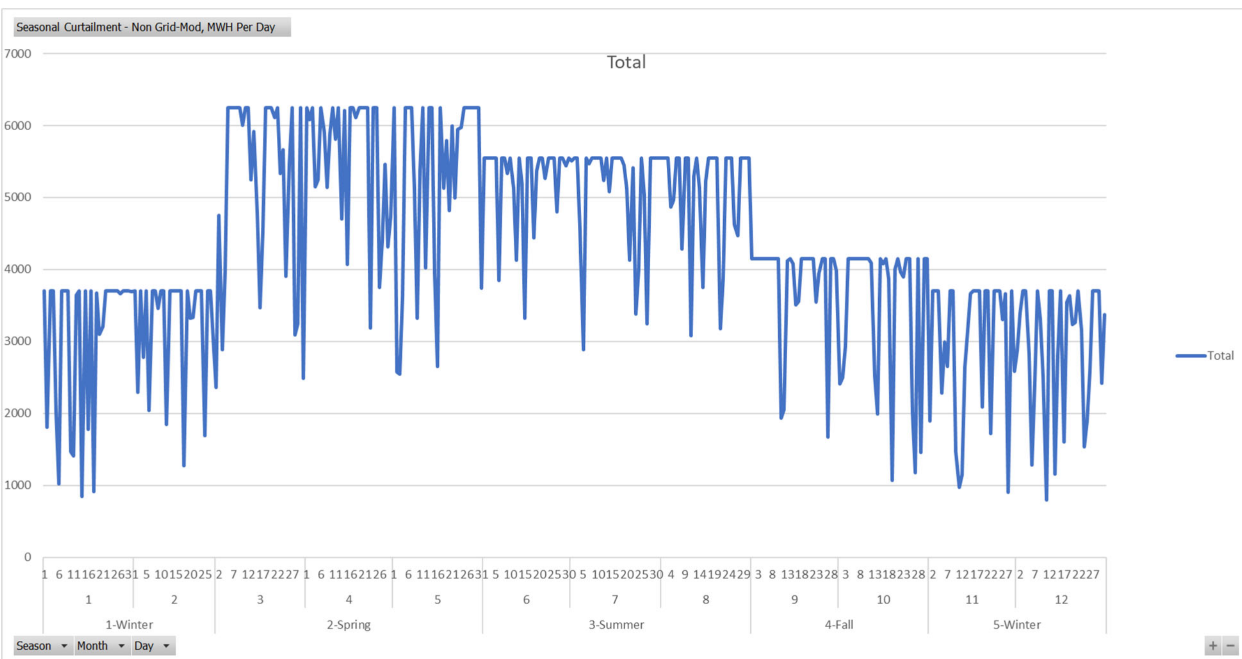


Figure 5.9: 2030 Daily Curtailment Across Seasons In the Grid Modernization Alternative (MWh / day)

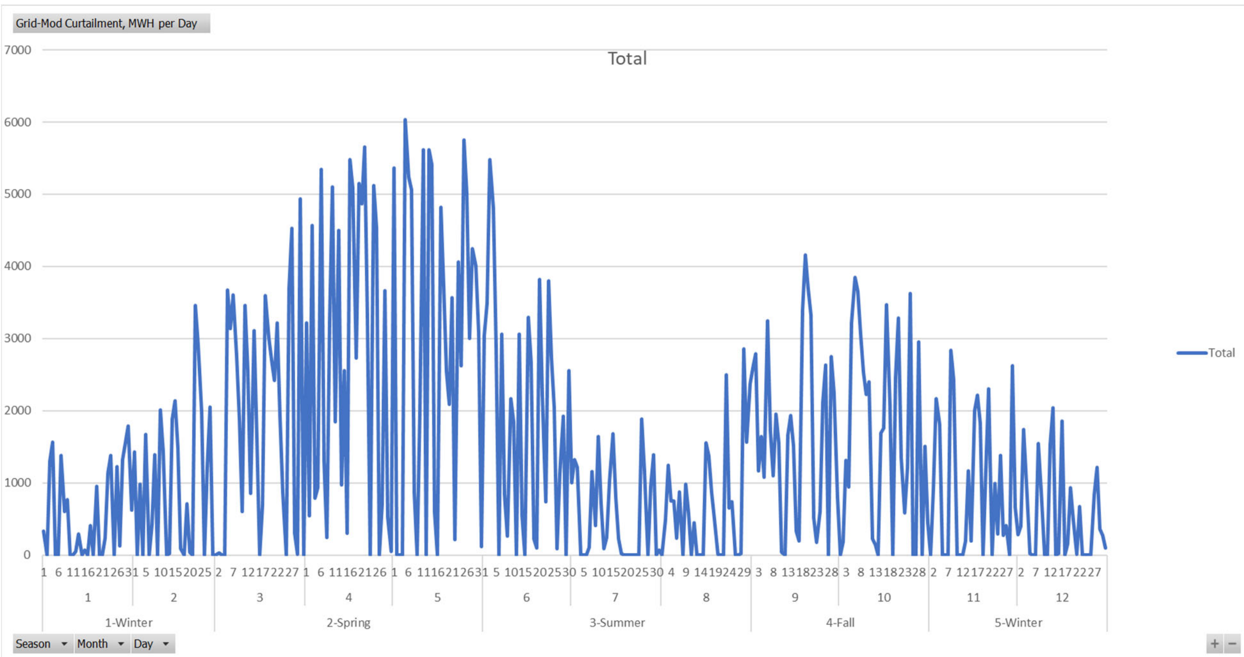


Figure 5.10: 2030 Daily Curtailment Across Seasons
In the Grid Modernization Alternative with Energy Shift (MWh / day)

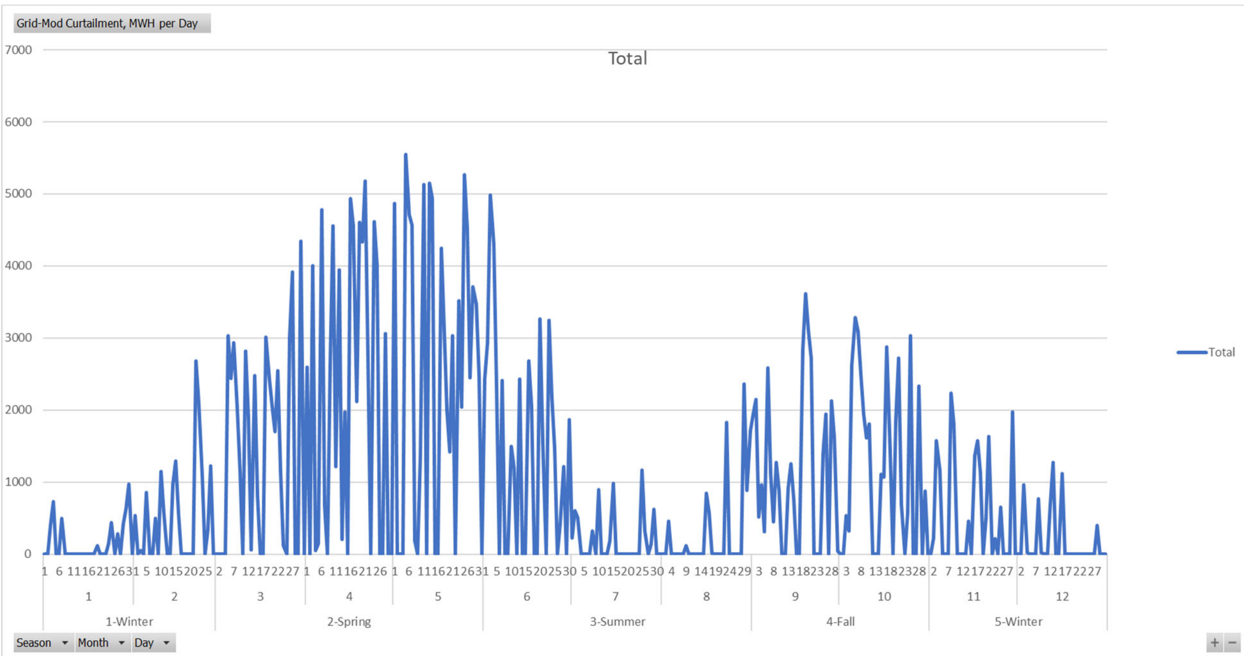


Figure 5.11 summarizes the curtailment as a percentage of the total annual energy production from distributed generation. There are four levels of DG curtailment for each "curtailment case" shown in Figure 5.11. They are sequential, building off the prior curtailment case that is listed in Figure 5.11. The first level is the percent curtailment that is needed for the No Grid Modernization alternative, which assumes that grid modernization is not adopted. In this case, the curtailment starts at 17.7% in 2030 and increases to 40.4% by 2040. For the No Grid Modernization case, the curtailment must be done in large, seasonal blocks because the distribution system operators cannot see what is happening on the system. In the Grid Modernization case, adding the grid modernization devices alone reduces the level of curtailment somewhat, from 17.7% to 4.1% in 2030 and in 2040, grid modernization alone reduces the level of curtailment significantly, from 40.4% to 17.6%. The percent of annual DG curtailment for the "GM & Energy Shift" case assumes the Grid Modernization alternative is adopted. In this case, by adding the energy shift from the various programs that will be enabled by AMF and GMP (Energy Insights, Whole House TOU/CPP and EV TVR) the curtailment is reduced further in 2030, from 4.1% to 2.8% and in 2040 the reduction is from 17.6% to 5.1%. Finally, in the "GM, Energy Shift & Energy Storage" case, the addition of controllable storage on the system reduces the curtailment to less than 1% in 2030 and down to 4.4% in 2040.

Figure 5.11: Curtailment as a Percentage (%) of Total DG Energy

Curtailment as a Percentage of Total DG Energy		
Case	Percent of Annual Energy (%)	
	2030	2040
No Grid Modernization	17.7%	40.4%
Grid Modernization	4.1%	17.6%
GM & Energy Shift	2.8%	5.1%
GM, Energy Shift & Energy Storage	0.7%	4.4%

5.8 Other Grid Modernization Benefits Determined Outside of the Distribution Study

Several other grid modernization benefits are summarized below that are in addition to avoided infrastructure cost and reduced DER curtailment requirements. The other benefits include ISO-NE system capacity and energy savings; reliability savings related to reduced outage time and faster restoration after storms; and reduced O&M cost related to operational efficiencies gained from distribution system automation.

1. **System Capacity and Energy Market Cost Savings** – VVO, TVR, and Demand Response that are enabled by grid modernization, will reduce the cost of procuring capacity and energy from the ISO-NE market due to the ability to shift demand. This calculation includes Capacity, Energy, and DRIPE savings. The DRIPE savings calculation reflects the lower clearing price in the ISO Energy Market and its effect on Rhode Island loads.
2. **Reliability Savings** – The reliability savings are based on benchmarking from PPL and other utilities that have implemented grid modernization over the past several years (i.e., comparing reliability data before and after grid modernization deployment). Rhode Island Energy's GMP will enable a FLISR system which will automatically isolate faults and sectionalize loads using Advanced Reclosers. This will, in turn, reduce the frequency of outages for all customers in Rhode Island. In addition, The Grid Modernization alternative will enable visibility and situational awareness of the distribution system which provides better information to more accurately dispatch crews for faster restoration, Storm restoration will be greatly enhanced due to situational awareness and visibility that is not provided in the No Grid Modernization alternative. Reliability impacts are discussed in Section 6 and the

quantification if the reliability improvement was done using the DOE ICE calculator as explained in Section 8.

3. **O&M Operational Savings** – Operational savings have been realized at PPL Electric and other benchmarked systems that have applied grid modernization in part due to better crew management, reduced truck rolls, and automation in daily system operations (e.g., Outage Management, Storm Response, etc.). O&M savings has been quantified in the BCA in Section 8.

5.9 Preliminary Analysis of Additional 115-kV Transmission Line in Western Rhode Island

The same conditions that were used in the Distribution Study for 2030/2040/2050 forecast were used as inputs to the Transmission Study to analyze the Rhode Island Energy bulk electric system requirements for the given conditions which included additional DGs, EVs, EHPs and any PV or onshore wind generation. A PSS/E steady state load flow model was used for the analysis that was applied to the appropriate system models provided by ISO-New England.[71] The study years for this assessment were 2031, 2040 and 2050. The purpose of the Transmission Study was to:

a) Determine the impact of off-shore wind integration to the Rhode Island Energy bulk electric system (345- and 115-kV networks).
b) Determine if the Rhode Island Energy distribution system load and generation conditions caused thermal loading or voltage violations to the bulk transmission system under expected peak and off-peak loading levels.
c) Determine if expansion of the 115-kV network in Rhode Island offered potential value to lower overall transmission and distribution infrastructure cost over the 2030/40/50 study period.

The Rhode Island Energy bulk electric system is defined as the 345-kV and 115-kV networks. These networks are operated as a looped system and are tightly integrated into the entire ISO-NE bulk electric system. The Rhode Island Energy sub-transmission and distribution networks, in the Distribution Study scope, operate in a radial manner with respect to its effect on the Rhode Island Energy bulk electric system. Even though the Rhode Island Energy sub-transmission and distribution system is primarily radial, it does have multi-directional power flow which could produce enough generation back feed onto the bulk electric system that it could potentially cause system issues. Therefore, to study the impacts of 2030/2040/2050 operating conditions, the net loading on the 345-kV and 115-kV transmission substations were determined using the CYME Distribution Study results. The CYME 8,760-hour Distribution Study identified generation and load data that resulted in the highest and lowest annual peak demand loading on the bulk transmission substations. The data consisted of DG's, EV's, EHP's and standard load expected to be in-service for the years 2031, 2040 and 2050. The data also contained information for additional state-jurisdictional PV and onshore wind generation. This information was

[71] PSS/E is a commercially available simulator software tool that is used by power system engineers to simulate electrical power transmission networks in steady-state conditions as well as over timescales of a few seconds to tens of seconds.

used as an input into the PSS/E system model to analyze the implications to the bulk transmission system in order to complete the Transmission Study.

Assumptions

The following cases were assessed for this study with a combination of interface transfers:

- 2031 Minimum
- 2031 Summer Peak (West-East only)
- 2040 Summer Peak
- 2040 Winter Peak (East-West only)
- 2050 Summer Peak
- 2050 Winter Peak (East-West only)

Impact of On-Shore and Off-Shore Wind

The offshore wind facilities that were assumed to be in-service in years 2031, 2040 and 2050 are shown below in Figure 5.12. These facilities were assumed to be available in the years shown and were set to 40% of the rated maximum output in the PSS/E model.

Figure 5.12: Offshore Wind Facilities In-Service in 2031, 2040 and 2050

Offshore Wind Facilities	2031	2040	2050
Rev Wind	X	X	X
Brayton Point	X	X	X
West Farnum		X	X
Kent County		X	X
Franklin Square			X

Information provided in Figure 5.13 was provided by distribution planning to determine the percentages of generation and load that was analyzed for the four respective scenarios in the Transmission Study.

Figure 5.13: Generation and Load Ratios Applied to Scenarios as Per Distribution Planning

Scenario	Load	DG	EV	EHP
Sum Peak	100%	10%	90%	0%
Sum HighDG	35%	100%	20%	5%
Win Peak2	50%	0%	70%	80%
Win HighDG	45%	100%	20%	10%

5.10 Transmission Study Results

Transmission Study results identified various overloaded transmission lines in most scenarios due to significant increase in load growth (driven by EV charging and EHPs) or increased PV penetration over the study period. In some instances, the increased penetration of DG caused the Distribution systems to supply or push power to the 115 kV transmission system through the distribution transformers. The list of transmission elements that exceeded their long-term emergency (LTE) ratings are shown in Figure 5.14.

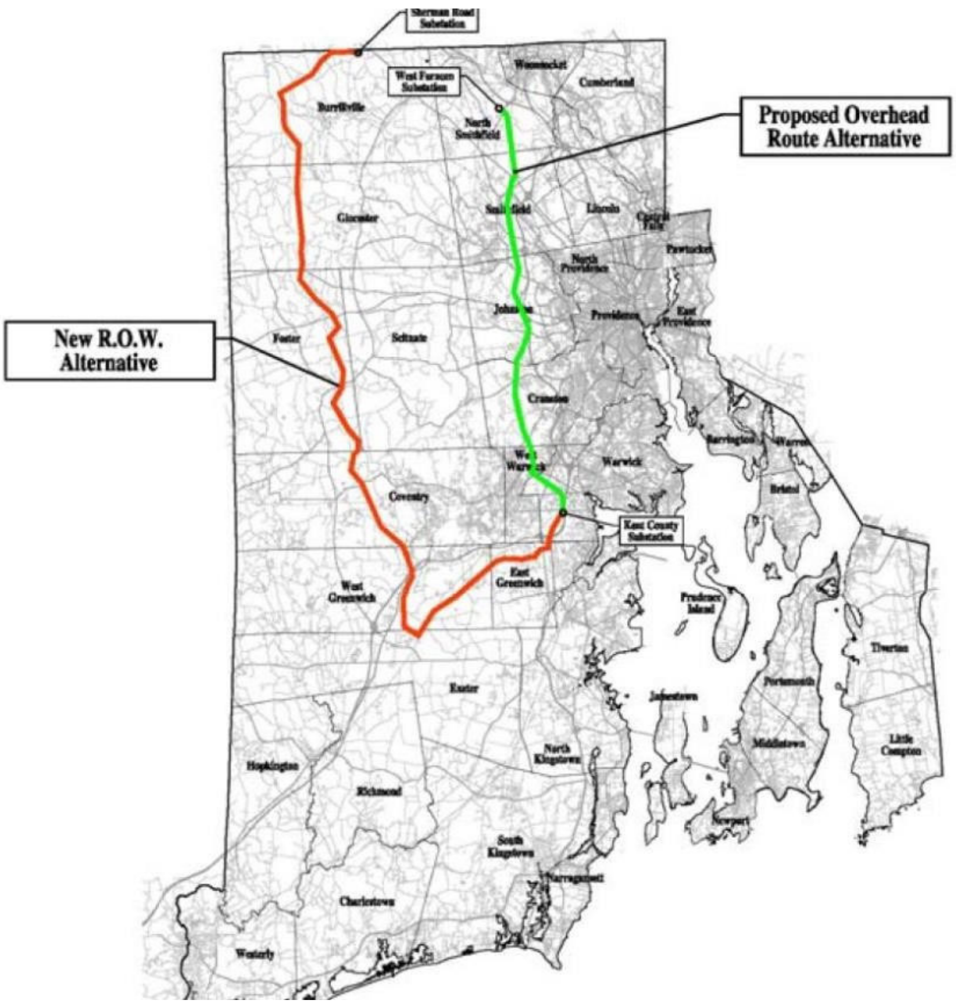
Figure 5.14: List of Overloaded Transmission Lines in years 2031, 2040 or 2050

Overloaded Transmission Elements
347 Line
West Farnum 174T
West Farnum 175T
Q-143 Line
Q-143S Line
R-144 Line
R-144N Line
X3N Line
P11 Line
R9 Line
E-183W Line
F-184N Line
E-105 Line
S-171N Line
T-172N Line
S-171 Line
T-172S Line
G-185S Line
L-190 Line
1870S Line
Franklin Square -Point St
L14 (Canonicus to Dexter) Line
M13 (Canonicus to Dexter) Line

Impact of Establishing a New 115-kV Transmission Line in Western Rhode Island

Various solutions were explored to address the overloaded transmission lines in Figure 5.14 above. A proposed 115 kV line between Kent County and Sherman Road (43.7 miles) was modeled as part of this study as shown in Figure 5.15. Three new substations were connected to the new line and existing generation/load was transferred from area stations to the three new substations.

Figure 5.15: Proposed 115 kV line between Kent County and Sherman Road



A sensitivity analysis was performed with the new 115 kV line modeled, and an additional 716 MW of new PV and 143 MW of onshore wind was also added to the new substations as summarized in Figure 5.16.

Figure 5.16: Additional PV and Wind Facilities Added to the New 115 kV Line

2030	2040		2050		
Wind (MW)	PV (MW)	Wind (MW)	PV (MW)	Load Moved to New Line (MW)	Wind (MW)
98	76	15	310	330	30

The interface flows for all the studied scenarios are as below:

Figure 5.17: West-East Interface Flow Cases

Interfaces	2031 Min W-E	2031 SUM Pk W-E	2040 SUM Pk W-E	2050 SUM Pk W-E
East-West (MW)	300	-2188	-1400	-1400
West-East (MW)	-502	2400	1600	1600
NE-SEMA/RI	-3280	-282	1575	155
SEMA/RI-NE	3000	500	-1400	160

Figure 5.18: East-West Interface Flow Cases

Interfaces	2031 Min E-W	2031 SUM Pk E-W	2040 SUM Pk E-W	2050 SUM Pk E-W
East-West (MW)	2700	3000	3100	2450
West-East (MW)	-2750	-3100	-3100	-2500
NE-SEMA/RI	-3800	-2600	-3900	-3325
SEMA/RI-NE	3800	2500	3900	3250

The proposed 115 kV line from Sherman Road to Kent County was also evaluated in all scenarios to identify the impact on the elements listed in Figure 5.16. The new line did not significantly impact the overloads for the West-East scenarios as the largest delta was +/- 2% in the 2050 Peak Day Cases. The new 115 kV line increased the transfers on the 115 kV paths from Kent County to Hartford Avenue by 2% while slightly alleviating the overloads north and east of Hartford Avenue.

The new 115 kV line created significant changes for the East-West stressed 2050 Winter Peak Day case. The Sherman Road to Kent County line reduced the transfers on the 115 kV lines south of West Farnum and north of Woonsocket while further overloading the 115 kV corridors from Grand Army to West Farnum and Hartford Avenue. The 115 kV corridors leaving Grand Army saw an average increase of 4-5% compared to the overloads witnessed in the original 2050.

In the Winter Peak case with the higher load levels attributable to EV charging and EHPs, the overloads on the 115 kV lines from West Farnum to Woonsocket and Hartford Avenue were **reduced by 4-6%** while the 115 kV corridor from Kent County to Eastern Connecticut saw the greatest improvement (**up to 11% reduction**) with the new 115 kV line addition.

The Transmission Study of the Rhode Island Energy 345- and 115-kV system was done using the PSS/E steady state load flow model with the sub-transmission and distribution system connected to it modeled as an equivalent. The results show that the expansion of the 115-kV system does have potential of reducing the overall T/D infrastructure cost as loading was reduced on multiple 115-kV circuits under peak load conditions.

Summary of 115-kV Transmission Line Review

1) Existing ROW is available to expand the 115-kV network in western Rhode Island
2) Adding additional capacity on the 115-kV network offers the opportunity to
   a. Unload the underlying lower voltage system
   b. Reduce system losses
   c. Increase hosting capacity
   d. Reduce overall T/D infrastructure costs
3) Evaluating this opportunity will require additional study

Because the load on the Rhode Island Energy network is projected to double by 2050 and the level of DER integration is projected to reach 5,000 MW, Rhode Island Energy will initiate an ***integrated*** bulk transmission, sub-transmission, distribution study to determine if converting a portion of the sub-transmission system to a higher voltage level offers efficiency and cost saving opportunities over the study period. This will require a review of the multiple configurations, will take considerable time, and is outside the scope of the GMP distribution study. This does not change the results of the Distribution Study, which demonstrates the Foundational Investments are required under any scenario to mitigate criteria violations and enable the Climate Mandates in Rhode Island to be achieved most effectively.

5.11 Distribution Study Conclusions

The Distribution Study compares two alternatives to solve system requirements identified through detailed planning analysis and applies a DER forecast to achieve the Rhode Island Climate Mandates by 2050. The Distribution Study identified many thermal and voltage violations on the distribution system with the CYME steady state load flow model that required major upgrades at both the distribution and sub-transmission voltage levels for both the No Grid Modernization alternative and the Grid Modernization alternative. The Grid Modernization alternative demonstrated that its functionality reduces the overall distribution level expenditures by over $1.3 billion Nominal as compared to the No Grid Modernization alternative. In addition, a comparison of how each Distribution Study alternative addresses the objective categories of operational, customer, and Climate Mandates is summarized in Figure 5.19 below.

Figure 5.19: Distribution Study Alternative Comparison Summary

Objective Category	No Grid Modernization Alternative	With Grid Modernization Alternative
Operational Needs	Lack of observability Inability to monitor & control Continued reliability degradation ***Safety/Reliability not achievable***	Full visibility and control Reduced outages Faster response time Optimization of Assets Reduced O&M Costs
Customer Needs	Higher Capacity & Energy costs High T/D Costs Inability to use TVR rates	Avoided T/D Costs Lower Energy costs Fewer outages Faster storm restoration Ability to use TVR/CPP/DR
Climate Mandates	High DER curtailment ***Climate Mandates not achievable***	Minimal DER curtailment

The Distribution Study illustrates the significant cost and benefit advantages to the Grid Modernization alternative. Additionally, two other critical conclusions can be drawn:

1. As DER penetration continues to increase with associated two-way power flow, the distribution system cannot be operated in a safe and reliable manner with visibility, situational awareness, and operational control that grid modernization provides
2. Rhode Island Climate Mandates cannot be achieved without grid modernization because of the excessive DER curtailment that would be required.

The Distribution Study confidently demonstrates that the Grid Modernization alternative that can be realized with the Foundational Investments is greatly preferred over the No Grid Modernization alternative under any scenario to mitigate criteria violations and enable the achievement of the Climate Mandates in Rhode Island most effectively. To explore further optimization for infrastructure investments, Rhode Island Energy will initiate an integrated bulk transmission, sub-transmission, distribution study that will expand upon the Transmission and Distribution Studies that were performed for this GMP to determine if converting a portion of the sub-transmission system to a higher voltage level and 115 kV expansion in Rhode Island offers additional efficiency and cost saving opportunities over the study period beyond that which has been identified through the Distribution Study.

Section 6

SECTION 6: GMP Roadmap with DER Management Functionality

This Section presents the GMP roadmap of near-term and future investments and the functionalities that those investments enable. This Section also discusses the importance of the DER Monitor/Manage functionality to the success of the GMP. Based upon findings from the Distribution Study in Section 5, the Foundational Investments are needed urgently and represent a "no-regrets" plan that will be coordinated through the annual ISR plan process. Finally, this Section presents customer-side integration opportunities through the integration of AMF and grid modernization functionalities.

The GMP Roadmap builds upon efforts that have been underway for several years in Rhode Island, first under the ownership of National Grid and now continuing under the ownership of PPL. The GMP benefits from adopting best practices, philosophies, and capabilities from PPL. As indicated earlier, the Company believes it is not possible to continue to provide electric service reliably and safely without adopting this new roadmap and implementing the Foundational Investments. The portfolio of integrated solutions that have been included in the Foundational Investments will give the utility the ability to manage the distribution system with more granularity. The investment in grid modernization in the near-term and future-term will result in a platform of solutions that enables beneficial electrification and interconnection of more DER, while also giving customers more control over their energy decisions, reducing energy use, and improving reliability.

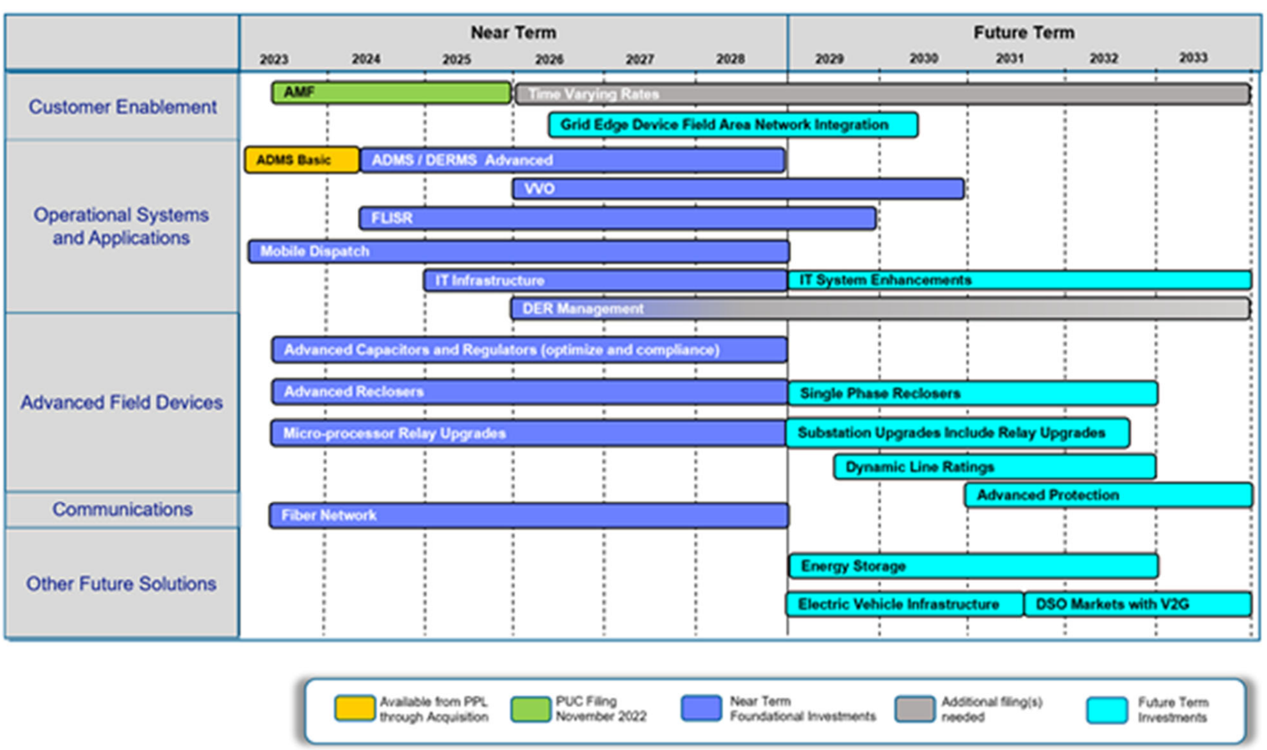
The Distribution Study presented in Section 5 demonstrates that the Foundational Investments are considered "No Regrets" in that they are required regardless of the future levels of DER penetration on the system. The Distribution Study also concludes that:

1) Safety and reliability cannot be maintained without the visibility, situational awareness, and automated control of the electric distribution network that is required given the two-way power flow conditions, which are being imposed on the electric distribution system today because of higher levels of DER penetration.
2) The Rhode Island Climate Mandates cannot be achieved even with massive T/D infrastructure buildout due to the amount of DER curtailment that would be required and the inability to monitor and control DER – Solar PV and storage batteries.

6.1 GMP Roadmap

The GMP Roadmap presents a sequenced progression of grid modernization investments that establishes fundamental grid modernization capability from highly integrated solutions. Within the GMP Roadmap, the blue bars identify the basis for the Foundational Investments that are considered "No Regrets" that are needed starting now and into the future to allow the distribution system operators to successfully and efficiently operate the modern-day grid regardless of the incremental DER penetration and future adoption rates. The Foundational Investments rely on AMF functionality beginning in 2026 at which time the meter deployment plan is scheduled to be complete. The plan also assumes functionality of ADMS Basic in May 2024. The GMP Roadmap forecasts the deployment of Foundational Investments to be significantly completed by the end of 2028 due to the urgent operational need. The Company has confidence in achieving this because of the preliminary GMP work that has been completed at Rhode Island Energy and the capabilities, experience and subject matter expertise that PPL brings to Rhode Island. As described in Section 1.8, PPL staff have extensive experience with grid modernization efforts evidenced by the installation and proven management of thousands of Advanced Field Devices, second-generation AMF and various grid modernization solutions over the last decade (see Section 1.8). The total estimated investment dollars for Foundational Investments in the GMP through 2028 is $316.9 million for distribution investments and an additional $23 million for transmission investments for a grand total of $339.9 million.

Figure 6.1: Rhode Island Energy Grid Modernization Solutions Roadmap



GMP Roadmap flexibility will be achieved by considering future-term investments as part of the Company's planning process and submitting proposals for those investments as part of the annual ISR plan process. A summary of the near-term Foundational Investments included in this GMP is provided below in Figure 6.2 and has been submitted in the FY2024 Electric ISR Plan. GMP Foundational Investments that have been included in the FY 2024 Electric ISR Plan are identified by program category throughout this Section. All systems required to support the Foundational Investments are included in this GMP or were included in the AMF Business Case.

Figure 6.2: Foundational Investment Estimates through 2028

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total Fiber Cash Flow	$ 8,270,000	$ 11,580,000	$ 18,240,000	$ 15,590,000	$ 8,160,000	$ 8,160,000	**$ 70,000,000**
Total ADMS Cash Flow	$ 107,143	$ 142,857	$ 3,224,375	**$ 1,600,625**	$ 4,476,875	$ 2,212,500	**$ 11,764,375**
Total IT Infrastructure Cash Flow	$ 1,545,000	$ 2,060,000	$ 3,060,000	$ 4,369,000	$ 4,936,000	$ 772,500	**$ 16,742,500**
Total Mobile Dispatch Cash Flow	$ 75,000	$ 100,000	$ 175,000	$ 200,000	$ 200,000	$ 50,000	**$ 800,000**
Total Recloser Cash Flow	$ 17,760,000	$ 25,779,600	$ 26,372,531	$ 26,979,099	$ 27,599,618	$ 7,081,011	**$ 131,571,859**
Total Cap Bank and Regs Cash Flow	$ 5,150,000	$ 6,956,400	$ 6,750,112	**$ 6,905,365**	$ 6,998,475	$ 1,120,413	**$ 33,880,764**
Total DER Monitor Manage Cash Flow	$ -	$ -	$ -	$ 2,288,076	$ 4,043,598	$ 4,414,290	**$ 10,745,964**
Total Electromechanical Relay Cash Flow	$ 3,405,000	$ 4,342,635	$ 6,687,320	$ 10,153,231	$ 8,472,589	$ 8,357,406	**$ 41,418,181**
	$ 36,312,143	**$ 50,961,492**	**$ 64,509,338**	**$ 68,085,395**	**$ 64,887,155**	**$ 32,168,120**	**$ 316,923,644**
Transmission Fiber	$ 3,285,714	$ 4,380,952	$ 7,666,667	$ 7,666,667	$ -	$ -	**$ 23,000,000**
GMP Foundational Investment Estimates	**$ 39,597,857**	**$ 55,342,445**	**$ 72,176,005**	**$ 75,752,062**	**$ 64,887,155**	**$ 32,168,120**	**$ 339,923,644**

Solutions for the near-term Foundational Investments are reasonably well defined, especially since most have been deployed at PPL Electric and PPL staff have significantly contributed to the preparation of this plan. However, the future functionalities will require additional definition and are subject to adjustment. The Foundational Investments will determine the real-time localized needs that would become inputs to future solutions, such as Vehicle-to-Grid and Storage opportunities, to be pursued as market and system conditions warrant. In the GMP Roadmap, the future-term GMP solutions are identified in turquoise. After the Foundational Investments are completed, the architecture will be in place to add and scale functionality and information platforms as needed. The future term solutions in the GMP Roadmap have not been quantified in the BCA because the Company understands there is a wide range of uncertainties that may result in acceleration or delay.

There are two solutions identified in the GMP Roadmap that will require additional regulatory approval. These solutions are Time Varying Rates and DER Monitor/Manage. For DER Monitor/Manage, the Company is assessing the legal and regulatory approvals necessary to permit DER Monitor/Manage and will make a separate filing for such approvals, including any tariff changes. *See* Attachment G.

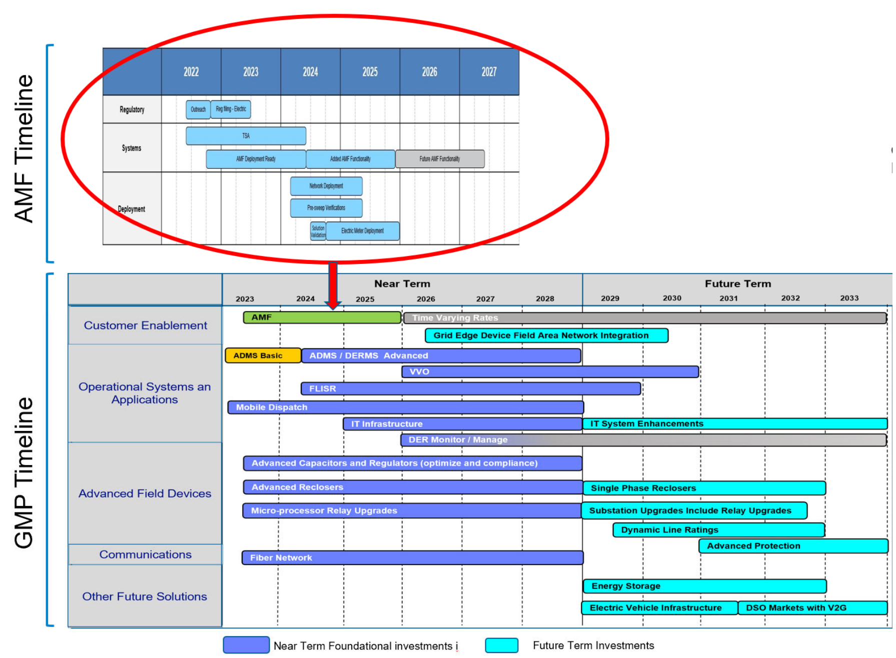
6.2 GMP Roadmap: Customer Enablement

The granular, timely, energy usage information provided by AMF will empower customers with enhanced understanding, choice, and control over their electricity consumption, enabling customers to reduce energy bills through greater insights about their energy cost drivers, personal usage, and new product and service offerings. AMF data and remote capabilities will support the following customer-side functionality in the near term and will also provide support to grid-side applications within the scope of the GMP, increasing operational efficiency, improving customer energy cost reductions, and better supporting the integration of DER.

Near-Term:

AMF: AMF integration is an integral component to the GMP and the GMP Roadmap. The plan assumes that the enhancing and foundational functionality defined in the AMF Business Case that was filed in November 2022 will be available within the GMP Roadmap. Granular, AMF meter data will be integrated with ADMS Basic/OMS as each AMF meter is exchanged starting in the middle of 2025. Below, AMF Project Timeline that was included as Figure 8.1in the AMF filing is overlayed on the GMP Timeline indicating how AMF and GMP deployments are coordinated. This image clearly displays the investments and technology deployments that are planned through the proposed AMF implementation.

Figure 6.3: AMF Project Timeline overlayed with the GMP Timeline



As a result, customers and the Company will realize operational benefits as the AMF meters are deployed. AMF brings many foundational and enabling functionalities to the GMP that are described in Figure 6.25 primarily due to the granular[72] load and voltage data which will be used as an input and integrated with all GMP operational platforms to update the real-time network model, which is critical for operations. The added granularity and resolution of meter data supports more accurate load-flow calculations, enables the operator to better understand and control power flows to successfully operate the modern-day grid with the use of ADMS and Advanced Field Devices. The granular AMF information provides a step-change of increased observability for the operator and grid planner, as compared to what is available today. AMF also provides automatic notification of outages, efficiently dispatches, and restore customers which will result in better customer service.

Time Varying Rates: Time Varying Rates ("TVR") are shown on the GMP Roadmap to start in 2026 after the AMF meters have been fully installed and pending approval of a separate filing for a proposed rate structure. TVR implementation is expected to lag behind customer meter installation to provide customers sufficient time to become familiar with their new meter and understand the new interval usage information and pricing options. The Distribution Study does assume that TVR will be available as one of the tools to shift peak and the BCA includes TVR availability in the benefit calculations. The AMF Business Case and GMP have coordinated the assumptions for TVR cost and benefits.

Future-Term:

The AMF deployment will offer future customer-side opportunity to pursue grid-edge applications and services (both customer facing and grid facing) as discussed in the AMF filing. These offerings will evolve after the AMF deployment in response to market and customer interests and readiness. These functionalities are known as other utilities across the country have advanced their grid modernization plans beyond the current GMP Roadmap activities.

Solutions in the Foundational Investments have assumed that the AMF functionality is available as defined. The costs for AMF and all Customer Enablement functionalities as well as the costs to integrate the AMF granular data into the operational systems have been included in the AMF Business Case and are not included in the GMP.

[72] Granular data is detailed data, or the lowest level that data in a target set. The granularity of AMF data is provided for through the availability of 15-minute interval, time sequenced data measurements. This level of measurement is much finer than historically offered making richness of information available for improved analytics and greater operational visibility.

6.3 GMP Roadmap: Operational Systems and Applications

A significant amount of IT planning, development, and system integration is required to achieve various GMP-enabled functionalities. Functionality releases are often dependent upon one another and require significant coordination. This is particularly the case as it relates to the GMP functionality being developed during and shortly after the development activities affiliated with the Transition Services Agreement ("TSA") exit[73]. The strategy is to align Rhode Island Energy's grid modernization systems to mirror the current grid modernization architecture and functions that PPL has used in Pennsylvania as closely as possible and to make those functionalities available no later than the TSA exit, currently planned for May of 2024. Rhode Island Energy currently utilizes National Grid's stand-alone OMS for all of New England that will be replaced with ADMS Basic at TSA exit as part of the Acquisition. A Network Manager SCADA system that includes both T&D device data as well as Energy Management System ("EMS") functionality is utilized for Rhode Island Energy transmission operations. A second similar Distribution Supervisory Control and Data Acquisition ("DSCADA") will be rolled out as part of ADMS Basic. This will allow for the integration of the DSCADA equipment status and device data with OMS to improve situational awareness, outage analysis and improve solution accuracy and granularity with advanced applications. A summary of the total estimated investments for Operational Systems & Applications is show in figure 6.4. The totals shown in Figure 6.4 include all project costs through 2028 as compared to the FY2024 Electric ISR Plan that includes only the installation portion of these project estimates.

Figure 6.4: Operational Systems and Applications

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total ADMS Cash Flow	$ 107,143	$ 142,857	$ 3,224,375	**$ 1,600,625**	$ 4,476,875	$ 2,212,500	**$ 11,764,375**
Total IT Infrastructure Cash Flow	$ 1,545,000	$ 2,060,000	$ 3,060,000	$ 4,369,000	$ 4,936,000	$ 772,500	**$ 16,742,500**
Total Mobile Dispatch Cash Flow	$ 75,000	$ 100,000	$ 175,000	$ 200,000	$ 200,000	$ 50,000	**$ 800,000**
Total DER Monitor Manage Cash Flow	$ -	$ -	$ -	$ 2,288,076	$ 4,043,598	$ 4,414,290	**$ 10,745,964**
Total Operational Systems & Applications	**$ 1,727,143**	**$ 2,302,857**	**$ 6,459,375**	**$ 8,457,701**	**$ 13,656,473**	**$ 7,449,290**	**$ 40,052,839**

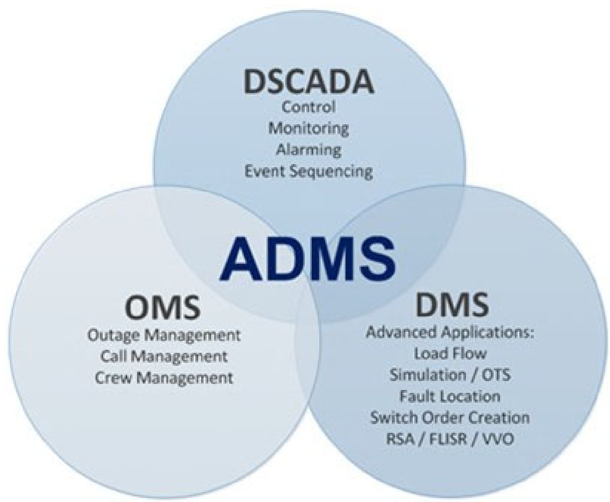
Near-Term:

ADMS: is central to the Operational Systems and Applications in the GMP Roadmap. It includes DSCADA, OMS, and DMS advanced applications that are integrated to enable a common network platform for operations. The advanced applications, as depicted in Figure 6.5, will enable distribution control center operators to make more optimal system configuration

[73] The TSA is an agreement between National Grid USA Service Company, Inc. ("National Grid Service Company") and Rhode Island Energy where, among other things, National Grid Service Company operates and maintains its back-office systems for Rhode Island Energy customers for up to two years after the Acquisition. During this period, customers will have their operations supported with National Grid systems in parallel, PPL and Rhode Island Energy will develop systems and processes so they can exit the TSA by transferring Rhode Island Energy business operations PPL systems.

decisions considering the actual constraints of the grid. As shown in Figure 6.4, the estimated cost for ADMS Advanced is $11.7 million.[74]

Figure 6.5: ADMS Advanced Applications

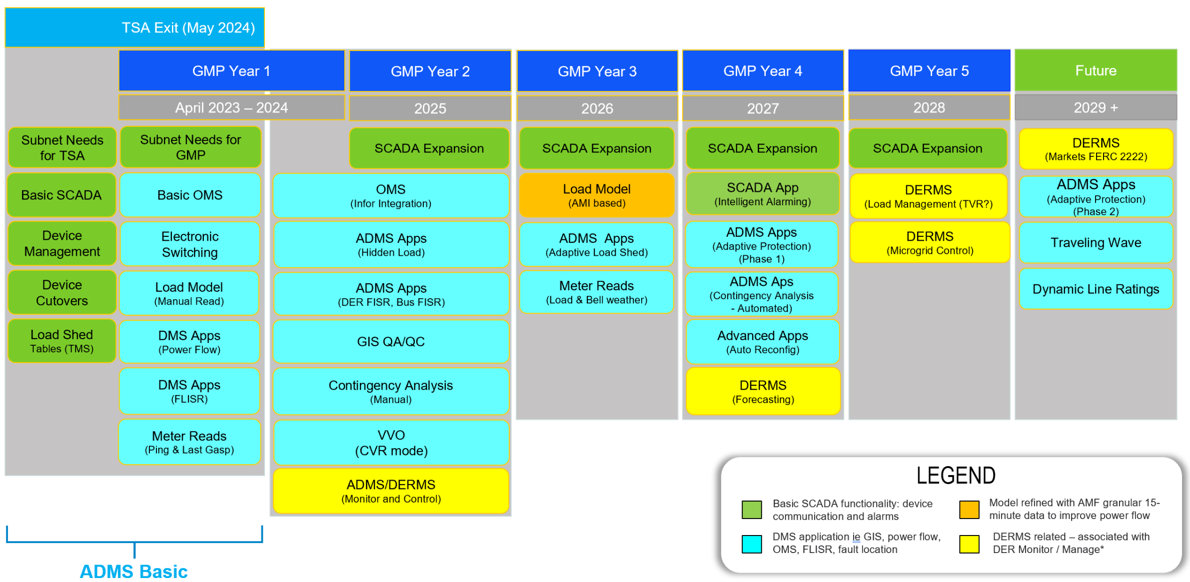


The ADMS Basic and Advanced system, associated software, and IT support systems are the brains of the Distribution Control Center. Currently, Rhode Island operators do not have a real-time load flow, so they rely on static system models and the distribution status information in SCADA (where available) to make operations decisions. For planned and emergency feeder reconfigurations, the operators utilize historic data, such as seasonal peak loading information, to help predict future conditions. Historically, system loading patterns have been somewhat predictable with regions, substations, and even individual feeders generally following similar trends. This is changing with the proliferation of DER as locational variability is increasing making real time load flow capability provided by ADMS a necessity that is critical for safe and reliable operation of the Rhode Island Energy distribution system.

Figure 6.6 identifies the timeline of ADMS and Operational Software Functionality that has been integrated with the GMP Roadmap.

[74] In this case, references to ADMS refer to the enhancements to ADMS Basic, the software platform PPL currently has in place for its other utilities, which Rhode Island Energy will also have in place for its operations upon exiting from the TSA.

Figure 6.6: ADMS and Operational Functionality Timeline



Timing of the functionality releases is divided into six (6) Groups that align with the milestones for ISR plan filings. ADMS is responsible for Observability, Power Quality Management, Distribution Grid Control, Grid Optimization, Reliability Management and DER Monitor/Manage functionalities. Definitions of these functionalities for ADMS Basic are included in Figure 6.7; definitions for ADMS/DERMS Advanced are included in Figures 6.10and 6.11.

ADMS accepts real-time information from advanced field devices and granular meter information to implement a variety of functionalities via a real-time network model. Examples of new functionality for improved operations are more accurate load-flow calculations that enable better control of power flows on the distribution system and optimize power output from renewable DER to relieve or avoid thermal or voltage constraints rather than investing in traditional solutions (e.g., reconductoring, substation upgrades). ADMS can also apply data analytics to significantly improve the load flow models used by distribution planners by creating actual loading and voltage profiles at all points along a feeder. This can result in more detailed load and DER forecasts for planning and operational needs. ADMS can accept automatic outage notifications and voltage alarms from granular AMF meters. This information is used for Power Quality and Reliability Management to improve voltage conditions and to pinpoint dispatching for efficient restoration. This new functionality is in sharp contrast to that available today, where feeder-level data combined with generic load shape analysis is used to model feeder performance. The timing of ADMS functionality has been closely coordinated with Advanced

Field Device installation assumptions and the timing of benefits for FLISR, VVO/CVR and DER Monitor/Manage.

GMP – Enabled ADMS Functionality Definitions

The GMP-enabled functionalities to be available with the ADMS Basic by May 2024 at the end of the TSA exit, is included in the first two columns of the ADMS roadmap with the corresponding definitions provided in Figure 6.7. The first two columns also describe the ADMS Basic functionality that will be available by the time the first AMF electric meter is exchanged. The remaining near-term ADMS solutions are defined in Figures 6.8–6.11 for GMP years 2–5 respectively. GMP year 2 aligns with the AMF electric meter deployment timeline. ADMS software functionality is in place before benefits are realized, often appearing on the ADMS Functionality charts a year before benefits are achieved. This allows time for Advanced Field Device installations to occur and operational time for benefits to be realized. Costs for the functionality through GMP years 1-5 have been included in the Foundational Investments.

Because the GMP platform can enable additional functionality beyond that described herein, the incremental costs and benefits associated with new capabilities that may be defined and developed in 2029 and beyond are not included in the Foundational Investments. As such, the development and integration costs for GMP future capability defined in Figure 6.12 was not included in the Foundational Investments.

Figure 6.7: Definitions of GMP-enabled Functionalities available with ADMS Basic

ADMS Basic FUNCTIONALITY	WORKING DEFINITION
Subnet	Data concentrator device used to aggregate 200 PTR's (Capacitors and Voltage Regulators) to one device for consumption by ADMS SCADA
Basic SCADA	The hardware and software needed to support the monitoring alarming & control of telemetered field assets, both inside and outside station boundaries. Rhode Island Electric uses two systems: TMS for transmission assets and ADMS for distribution assets
Device Management	Database and UI used to manage the adds, deletes, and modifies of distribution telemetered assets
Device Cutovers	The work to program and convert all current SCADA devices to the PPL host systems
Load Shed	Software that controls the operation of circuit breakers to reduce load when called for by ISO-NE.
Basic OMS	Hardware and software needed to receive customer calls, predict to common devices, keep customers informed, and manage the execution of the work to restore/repair the issues. Does not include auto dispatching or remote dispatching
Electronic Switching	Application within ADMS that allows DCC personal to write, review, and execute switching orders electronically
Load Model (manual)	The customer load information and processes required to run distribution power flow (DPF). Based on the monthly usage reads
DMS Apps (FLISR)	The automated switching application with ADMS that determines outage locations, determines and ranks suitable switching options, and executes the most desirable based on a configurable set of criteria (Performance Index)
Meter Reads (Ping and Last Gasp)	Ability and connections between ADMS and AMF that brings real time meter information (Power Down & Power Up) to ADMS

Figure 6.8: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 2

ADMS FUNCTIONALITY GMP Year 2	WORKING DEFINITION
OMS (Infor Integration)	Adds the ability to send outage tickets to mobile units in field workers trucks and unlocks the ability to automatically dispatch to appropriate crews dependent on a configurable rule set
ADMS Apps (Hidden Load)	The modeling and software configuration within ADMS to understand the amount of load that is being masked by DER penetrations. Used in FLISR application and planned work study scenarios
ADMS Apps (DER FLISR & Bus FLISR)	The modeling and software configuration within ADMS to make available the ability of FLISR to account for the DER's that will NOT be on immediately following restoration. Also includes functionality to support FLISR plan creation and execution for substation bus outages – dependent on hardware and feeder offload availability
GIS (QA/QC)	The work required to validate the data integrity of the external distribution system network model to support voltage control
Contingency Analysis (manual)	Ability to study planned bus outages for risks associated with the switching required and to determine suitable alternate plans
VVO (CVR mode)	Voltage control application with ADMS that reduces distribution system voltage to the low side of the ANSI required band and optimizes the use of all distribution feeder voltage control assets
ADMS/DERMS (monitor & control)	The modeling and software required to connect to "behind the meter" asset inverters. Data used in ADMS DPF application and controls to allow for increased voltage control options and real power ramping to minimize DER curtailment

Figure 6.9: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 3

ADMS FUNCTIONALITY GMP Year 3	WORKING DEFINITION
Load Model (AMF based)	Enhanced ADMS load model based on AMF 15-minute reads
ADMS Apps (Adaptive Load Shed)	The modeling and configuration to enhance TMS load shed application to rank the feeders based on real time data and system configuration. Eliminates the need to manually manage load shed tables and schemes
Meter Reads (Load & Bell weather)	Ability of ADMS to read and make use of near real-time customer meter load and voltage information

Figure 6.10: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 4

ADMS FUNCTIONALITY GMP Year 4	WORKING DEFINITION
SCADA App (intelligent alarming)	Software and configuration process required to reduce the overall alarm fatigue caused by the introduction of multiple telemetered devices installed per feeder
ADMS Apps (Adaptive Protection P1)	Software and configuration to allow FLISR to select new pre-programmed settings groups when performing automated restoration switching
ADMS Apps Contingency Analysis (Automated)	Ability to automatically analyze planned bus outages for risks associated with the switching required and determine suitable alternate plans if required
ADMS (Auto - Reconfiguration)	Software and configuration within ADMS that detects voltage and load exceptions and determines suitable switching solutions to resolve the issue
DERMS (forecasting)	Software and configuration that perform DER and Customer Load forecasts for use by ADMS power flow and other distribution operations applications

Figure 6.11: Definitions of GMP-enabled Functionalities available with ADMS GMP Year 5

ADMS FUNCTIONALITY GMP Year 5	WORKING DEFINITION
DERMS (load management TVR)	Software and configurations that send signals to customer assets based on Demand Response and Time Varying Rate programs
DERMS (Microgrid Control)	Software and configurations that monitor distribution system status and coordinate the start-up, operation, and shutdown of attached microgrids

Figure 6.12: Definitions of GMP-enabled Functionalities available with ADMS GMP Future

ADMS FUNCTIONALITY Future Term	WORKING DEFINITION
DERMS (FERC 2222)	Software and configurations that allow for full DSO (Distribution System Operator) functionality as ultimately defined by FERC 2222
ADMS Apps (Adaptive Protection P2)	Software and configuration to allow pre-defined distribution system conditions to initiate an automated protection review. If relay settings changes are needed; new relay files are produced and downloaded to the appropriate microprocessor relays
Traveling wave	Used for predictive failures (traveling wave fault protection)
Dynamic Line Ratings	Used to improve line operation capabilities dependent on real-time weather conditions (temperature, wind, etc.)

Volt Var Optimization ("VVO"): Volt/VAR Compliance and Optimization map to the Power Quality Management and Grid Optimization Functionalities. VVO is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices or VAR control devices that are dispersed across distribution feeders. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile, or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder to the tail-end in concert with capacitors and other voltage regulating devices for voltage support. With VVO, voltage can be monitored along the feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be lowered to achieve energy efficiency and peak reduction. As penetration of DER grows, enhanced voltage control through VVO will allow Rhode Island Energy to better manage the expanded range of distribution system voltage cause by DER. VVO is a near-term functionality enabled by ADMS where benefits start accumulating in 2026 and incrementally build over the remaining five years as smart capacitors and regulators are installed in the field. As discussed in the BCA, 20% of the potential VVO benefit is assumed to be available in 2026 leveraging the Advanced Field Devices and granular information from the fully deployed AMF meters. From a benefits perspective, AMF meters provide greater resolution and capability resulting in .5% energy savings (which is provided in the AMF Business Case); while an additional 2% energy savings is attributed to Advanced Field Devices and ADMS. The DER Monitor/Manage functionality will enable inverter controls to adjust real and reactive output of DER which will greatly enhance the capability of VVO.

Fault Location Isolation and Service Restoration ("FLISR"): FLISR is ADMS software technology that reduces outage impact and duration. Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, and FLISR in the near-term, while preparing the Company to implement advanced applications like Distributed Energy Resource Management System ("DERMS"). FLISR is a core application within ADMS that will be made available with ADMS Basic. The primary function of improving distribution system reliability by isolating a faulted segment of a feeder and automatically restoring power to available un-faulted segments. The FLISR application relies on three primary components to operate: (1) ADMS, for the central control and logic; (2) communications to each device; and (3) Advanced Field Devices (reclosers) to detect faults, isolate where possible and operate when commanded by ADMS. As discussed in Section 1.9, FLISR is expected to reduce the frequency of outages (SAIFI) by up to 30%, and decrease CEMI, which is the metric of how many customers experience multiple interruptions one or more times. FLISR will bring a number of benefits described in the Distribution Grid Control, Reliability Management, and Grid Optimization Functionalities. They also have accurate voltage sensing which will contribute to VVO for Power Quality Management. With ADMS - FLISR, each Advanced Field Device needs to have two-way communications and the ability to be remotely operated to work. As more feeders are automated and more devices are remotely controllable, FLISR will have the ability to perform complex switching to restore as many customers as possible and in addition, the system can propose additional switching steps which can be done manually to restore more customers while the cause of the outage is being addressed. Existing intelligent, remotely controllable switching devices that exist on the Rhode Island Energy feeders will all be transitioned to ADMS control over time for use with FLISR.

Advanced Field Devices (Reclosers): Reclosers are scheduled to be installed starting in 2023. Benefits from FLISR start accumulating in the BCA beginning in 2024. The ramp-up of accumulated benefits correlate to the Advanced Field Device installations where the full reliability benefits are achieved starting in 2030.

Mobile Dispatch: Today dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS to view customer calls and predicted outage locations. They prioritize the "trouble calls" and outages and assign them to appropriate field crews based on capability and location as optimally as possible. ADMS-based Mobile Dispatch will interface with OMS and allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews and crew time and shorten "trouble calls" and outage response times. In addition, field crews will be able to update details concerning their time of arrival, incident details once on location, and estimated restoration times rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near real-time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand.

The proposed Mobile Dispatch project includes a limited deployment of mobile dispatch capabilities to select field personnel, with a view to explore options to improve the "trouble calls" response and outage restoration process. Learnings from the pilot project will be applied towards developing the de-centralized process flows andrequirements for a full deployment. Mobile Dispatch is expected to improve outage restoration times, the efficiency and accuracy of restoration efforts, and worker safety. The Mobile Dispatch application will be placed in service incrementally as components of the GMP are completed. The funding requested includes Foundational Investments from 4/1/23 – 12/31/28. As shown in Figure 6.4, the estimated cost for Mobile Dispatch is $800K.

IT Infrastructure: The IT Infrastructure Plan includes investments that will build foundational data management capabilities by enabling enhanced data governance across key datasets including an enterprise integration platform that will provide all the necessary integrations between the various GMP applications such as ADMS, VVO/CVR, data management and storage, and GIS integration. This plan also includes a cyber services component that is built from the principles and policies established in the PPL Data Governance Plan, filed as Attachment H in the AMF Filing and Attachment J in this filing. The Foundational Investments include proposed underlying IT infrastructure investments in data management, enterprise integration platform, and data storage necessary to enable grid modernization functionalities and realize its full benefits. The Company considers cybersecurity a necessary capability to operate a safe, reliable and cost-effective electric distribution system. Cybersecurity protects customers and electric grid operations from a vast array of threats. As more intelligent devices, including third-party devices, are interconnected, and integrated with utility operations, the number of potential targets increases, as does the need for a robust cybersecurity program. The IT Infrastructure will be placed in service incrementally as components of the GMP are completed where Foundational Investments span April 2023 – December 2028. As shown in Figure 6.4, the estimated cost for IT Infrastructure is $16.7 million.

DER Monitor/Manage: DER Monitor/Manage is a grid modernization functionality that enables the visibility of DER and the ability to manage them, further described in Attachment G. This management ranges from ramping operations of an individual DER real and/or reactive output to full curtailment, if needed, for safety or reliability purposes. Visibility is an attribute that enables DER to automatically alert the distribution system operator of their presence on the grid as well as their various characteristics, such as rated capacity and power imports or exports over time. Where DER are both visible and controllable, their operation can be managed to minimize negative impacts to the grid while optimizing the benefits to DER-owning customers and to other customers. Visibility and controllability are prerequisites for fully ***integrating*** DER into the grid. As shown in Figure 6.4, the estimated cost for DER Monitor/Manage Foundational

Investments is $10.7 million.

ADMS – DERMS application is used in conjunction with DER Monitor/Manage field devices to access inverters. The "Reference Case" for the No Grid Modernization Alternative in the Distribution Study (see Section 5) assumes the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the design limitations of the system. This would result in an average renewable DG seasonal curtailment of 17.7% of its annual energy output in 2030 and 40.4% in 2040. The Distribution Study assumed the Grid Modernization alternative would utilize DER Monitor/Manage in conjunction with energy shifting techniques to reduce annual DG curtailment approximately to 0.7% per year in 2030 and 4.4% in 2040. This DER Monitor/Manage functionality will maximize renewable energy production, optimize the use of T/D infrastructure, avoid new infrastructure spend, improve the customer experience, improves power quality, and increases hosting capacity.

Several components will be used for DER Monitor/Manage involving interconnecting DER to the electric distribution system, communicating to DER management devices, receiving and integrating operational feedback from DER for system analysis, calculate dynamic operation settings for DER, and manage settings changes as needed. See Section 7 for more details.

6.4 GMP Roadmap: Advanced Field Devices

As mentioned earlier, solutions for the near-term Foundational Investments include advanced field devices. The total estimated investments for advanced field devices is presented in Figure 6.13.

Figure 6.13: Foundational Investments Advanced Field Devices

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total Recloser Cash Flow	$ 17,760,000	$ 25,779,600	$ 26,372,531	$ 26,979,099	$ 27,599,618	$ 7,081,011	**$ 131,571,859**
Total Cap Bank and Regs Cash Flow	$ 5,150,000	$ 6,956,400	$ 6,750,112	**$ 6,905,365**	$ 6,998,475	$ 1,120,413	**$ 33,880,764**
Total Electromechanical Relay Cash Flow	$ 3,405,000	$ 4,342,635	$ 6,687,320	$ 10,153,231	$ 8,472,589	$ 8,357,406	**$ 41,418,181**
	$ 26,315,000	**$ 37,078,635**	**$ 39,809,963**	**$ 44,037,694**	**$ 43,070,682**	**$ 16,558,830**	**$ 206,870,805**

Near-Term:

Advanced Capacitors and Regulators: With current levels of DER penetration, dependence on a daily load cycle is no longer possible and the need for on-site sensing is increasing. In response, the Company has revised its standard capacitor control to an electromechanical relay that is activated based on current (i.e., amps) and voltage (i.e., volts) at its location and switches the capacitor on or off as necessary. Accelerated deployment of smart capacitors and regulators with advanced controls will provide voltage and reactive power control to enable management of voltage along the distribution feeder within required ANSI voltage standards. The Foundational Investment for advanced capacitors is based on replacing or upgrading 808 capacitors and for regulators the investment is based on replacing 80 regulators.

For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range which is +/- 5% of the nominal value. For example, nominal delivery voltage may be 120 volts for a residential customer with an acceptable range of 114 to 126 volts. Coincident voltages along the distribution system will vary by location on the feeder, and the voltage at any delivery point will also vary with time.

In the past, voltage regulation was relatively predictable. With one-way power flows, voltage tended to "drop" from the head-end of the feeder to the remote-ends of the feeder due to the resistance of the wires and the distribution of load along them. Key variables for distribution planners to consider in determining how much voltage drop to plan for are a feeder's load profiles and electrical impedance. To compensate for this voltage drop, capacitors and voltage regulators have traditionally been installed to boost the voltage to stay within the required voltage range. For capacitors, a planning rule of thumb was to install "Fixed" capacitors (which are always on) to accommodate the voltage drop at minimum load levels and "Switched" capacitors to compensate for voltage drops at peak load levels. Since electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. An example of a simple time clock control is shown in Figure 6.14 along with a new programmable-type control unit.

Figure 6.14: Time Clock Control & New Programmable Logic Control Components

Simple autonomous settings are insufficient for Rhode Island Energy to maintain compliance with voltage standards for modern-day feeders with a high level of intermittent renewable DG that cause significant voltage fluctuations. Generation-based DER, such as solar and wind DG, are forecasted to create overvoltage during light load periods, while load-based DER, such as EV charging, are forecasted to create under-voltage issues during peak load periods. While the examples provided in Figures 6.15 and 6.16 present voltage issues, the Company anticipates these issues will be systemic by the year 2030, as these issues are arising in isolated areas already. Likewise, voltage constraints are being identified in interconnection studies and are limiting hosting capacity for many new interconnection applications.

Figure 6.15: Peak Load, Modeled Week of July 21-27, 2030

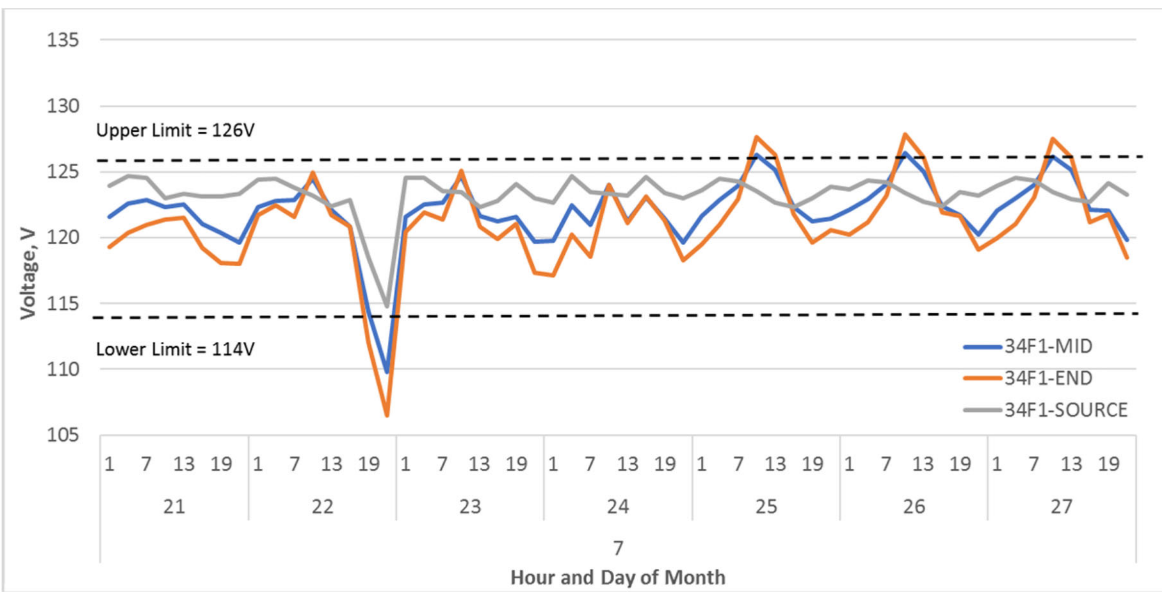


Figure 6.16: Light Load, Modeled Week of May 21-27, 2030

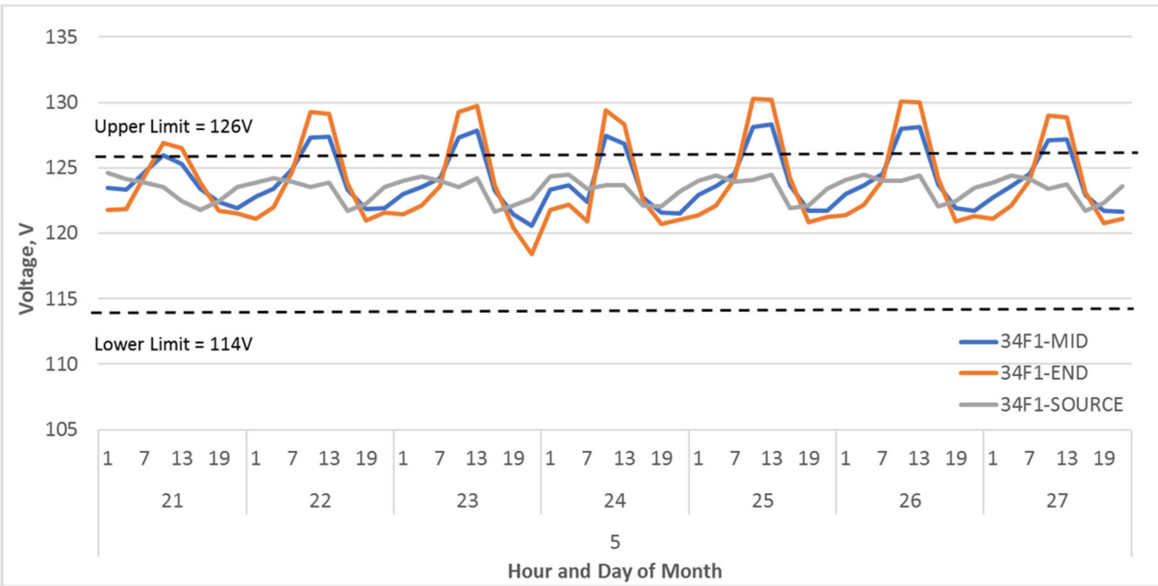


Figure 6.17: Example Overvoltage and Under-Voltage Risks
(Feeder – 34F1; Forecast Year – 2030; Scenario – High DER; Voltage basis –120V nominal, ANSI normal +/- 5% = 126V upper limit, 114 V lower limit)
Load Swing, Modeled Week of January 21-27, 2030

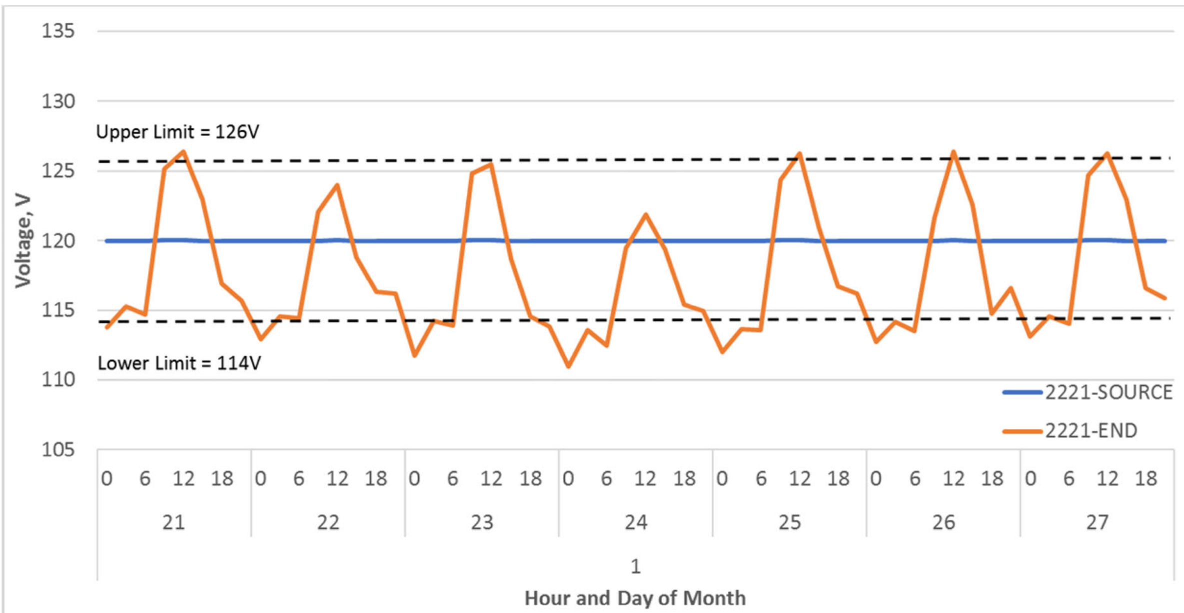
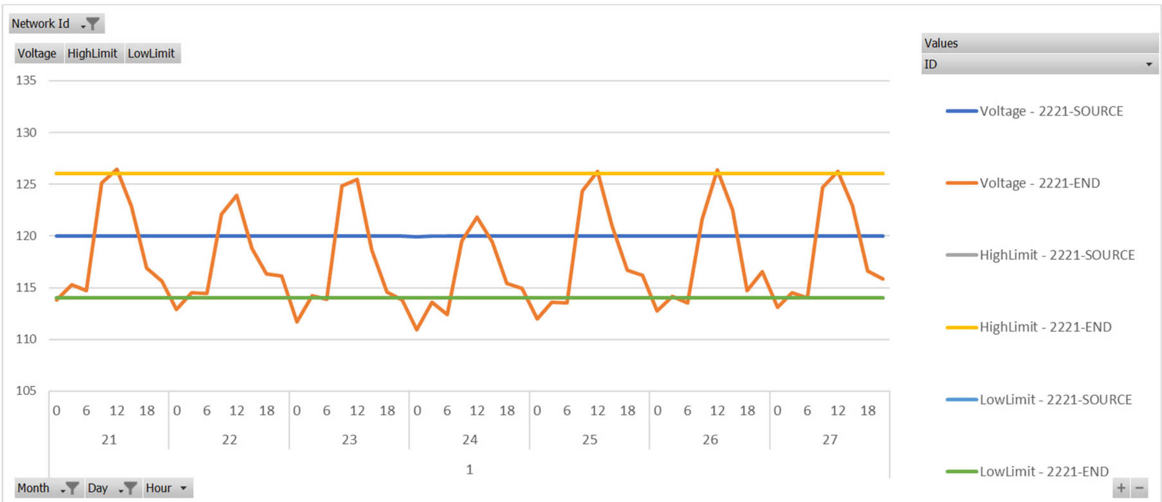


Figure 6.18: Example Sub-Transmission Overvoltage and Under-Voltage Within Same Day
(Line – 2221; Forecast Year – 2030; Scenario – High DER; Voltage basis – 120V nominal, ANSI normal +/- 5% = 126V upper limit, 114 V lower limit)



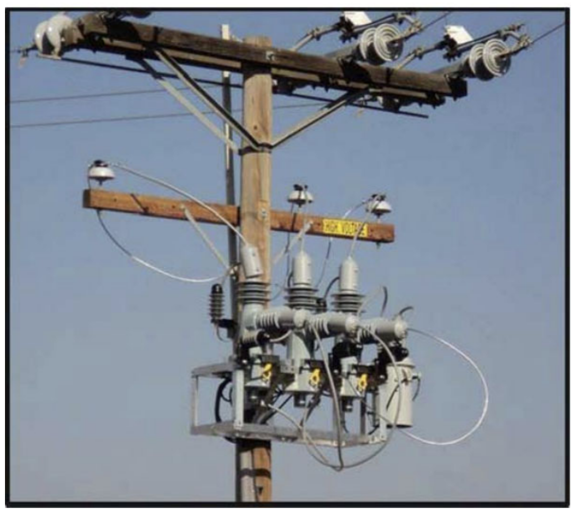
To alleviate these issues, the proposed Advanced Capacitors and Regulators would adjust system voltages up and down in a dynamic manner to accommodate the variable output of DER technologies. For example, as solar DG output increases system voltage, capacitors would switch off and regulators would adjust tap positions to accommodate the voltage change within the acceptable range. As solar DG output decreases and residential EV charging increases in the evening, the capacitors would switch back on and the regulators would readjust to address the voltage drop.

Smart capacitors and regulators are scheduled to be installed starting in 2023, though the benefits from VVO start occurring in 2026 after the granular AMF meter information and ADMS -VVO software is available. The existing VVO deployment on select feeders will be converted to ADMS. Areas of highest compliance risk and high DER penetration will be targeted. Existing fixed capacitors will either be by-passed or modified with advanced controls to eliminate causes of high voltage during minimum load conditions. All existing switched capacitor banks without advanced controls will be modified to include advanced controls. New smart capacitors and regulators will be added at strategic locations to minimize compliance risk and to enable VVO benefits. The accelerated deployment of advanced capacitors and regulators will enable VVO, starting in 2026, which results in significant savings, and operational benefits.

Advanced Reclosers: Advanced Reclosers are switches that can interrupt power flow in response to a short circuit and then automatically allow power flow to resume a short time later.

The foundational GMP investment for advanced reclosers is based on replacing 1,561 reclosers. Typically deployed throughout a distribution grid, reclosers are used to isolate customer outages due to temporary faults via automatic sectionalizing and restoration. The Advanced Field Device is a breaker equipped with a mechanism that can automatically close after it has been opened due to a fault. The programmable electronic controls allow close coordination with other devices, and enhanced sensing capabilities, that when enabled with communications, can send operating information and a field crew can be dispatched to fix a fault when the reclosing operation doesn't eliminate the problem.

Figure 6.19: Recloser on a Distribution Pole



FLISR reclosers will be pole-mounted remote supervisory reclosing and switching devices. They will also be able to report fault current to ADMS, which provides the ability to identify the possible location of the fault. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will open and remain open, then communicate information about the fault event to ADMS. The ADMS/FLISR functionality is the critical operating system for Reliability Management. FLISR technologies and systems involve advanced reclosers/switches, line monitors, communication networks, ADMS, OMS, SCADA systems, grid analytics, models, and data processing tools. These technologies work in tandem to automate power restoration, reducing both the impact and length of power interruptions.

FLISR identifies a fault on the electric grid and minimizes its impact on the customers as quickly as possible. It is an automatic process that identifies the fault, isolates it, and redirects power to as many of the customers affected by the fault as possible. The fault is identified using sensing from Advanced Reclosers, AMF meters, Advanced Capacitor banks, and Microprocessor relays that monitor the flow of electricity and measure the magnitudes of fault currents. As soon as the fault is identified, advanced reclosers are opened to isolate the fault and then closed to redistribute power to the affected customers.

Safe and reliable service is provided by ensuring equipment operated within its rated capacity and that faults on the system are cleared in a fashion that prevents damage to equipment and limits service interruptions to as few customers as possible. Increasing customer DER adoption adds complexity to managing distribution system loading and the protection systems. This requires sensing from field devices, ADMS/FLISR software and Advanced Reclosers on the distribution feeders. In addition to having Reclosers isolate faulted line segments and tie line reclosers to allow transferring customers to adjacent feeders, these devices will become increasingly important to sensing systems conditions, balancing load and generation on the distribution system, and curtailing commercial sized DER, when needed. They will also need to be equipped with the ability to perform ADMS-based protection to dynamically adjust protection schemes based upon the dynamics of the system. Advanced Reclosers support or enhance several other key functionalities, including Observability (Monitoring and Sensing), Power Quality Management, Grid Optimization, and DER Monitor/Manage.

Recloser installations start as soon as 2023 and the corresponding reliability gains are expected to start shortly thereafter beginning in 2024. The accelerated installation of the Foundational Investments will allow for Reliability performance improvements as soon as possible (see Section 1.9). This capability is enabled by having ADMS Basic available to Rhode Island Energy in 2024.

A reliability analysis was performed and the results show that reliability will increase up to 30% by installing reclosers and using them in conjunction with the ADMS- FLISR application available in ADMS Basic. The assessment to determine the reliability improvement compared mainline outage reliability data averaged over the last five years to that expected if reclosers are placed using a segmentation criterion of 500 customers between devices.

The calculation uses Blue Sky Day numbers used in the table below. To determine the reliability improvement:

- **Existing:** 207,191 customers that experience a mainline interruption.
- **With Reclosers:** If reclosers are installed across the system using the 500 customer segmentation criteria, then there would be 79,500 customers impacted by the same 159 events using reclosers. (500 customers per event x 159 events = 79,500)
- **Results:** The customer interruptions saved using reclosers is 127,691 (207,191 – 79,500).
- **SAIFI impact:** Divide the customer interruptions saved by the average customers that are served 127,691/495,622 resulting in an estimated SAIFI improvement of 26% annually.

Analysis was also done "with major storm" to indicate that reclosers positively impact resiliency. Using the methodology described above, the number of which show that customers that would be impacted by severe weather would be reduced. Also, if a customer does realize an outage, the time it takes to restore them will be less. As mentioned above, in addition to the reliability benefits, the reclosers offer numerous other advantages such as improved system visibility, flexibility for system configuration, enhanced protection capability, voltage data to improve volt/VAR optimization analysis, and a host of operational efficiencies.

Figure 6.20: Rhode Island Energy Reliability Impact with and without GMP Reclosers

Average Annual Reliability Impact With & Without GMP Reclosers Circuit Breaker and Recloser Events January 2017 through December 2021				
Day Type	Blue Sky Day *		Major Storm (IEEE TMED)**	
Customers per recloser	500	1000	500	1000
RI Energy Average Cust Served	495,622	495,622	495,622	495,622
# of events	159	159	122	122
CAIDI (min)	66	66	813	813
Total CI	207,191	207,191	143,120	143,120
Average CI / event	1,303	1,303	1,171	1,171
CI with GMP Reclosers / event	500	1,000	500	1,000
Total CI with GMP Recl.	79,500	159,000	61,100	122,200
Delta CI	**127,691**	**48,191**	**45,825**	**15,690**
SAIFI improvement	0.258	0.097	0.092	0.032
Delta CMI	**8,405,116**	**3,180,606**	**37,241,256**	**12,750,894**
SAIDI Improvement (min)	16.96	6.42	75.14	25.73

** Assumes automated switching takes less than 1 min. **Assumes 75 % successful operations during storms.*

This assessment indicating that the SAIFI reliability improvement of approximately 26% for Rhode Island Energy with reclosers installed using the 500 customer segmentation criteria aligns with estimated benefits published by DOE where four projects reported SAIFI improvements of 11 – 49%.[75] It also aligns with PPL Electric's experience where they have realized SAIFI improvement of approximately 28% since installing advanced recloser throughout the service area using the same segmentation criteria of 500 customers in conjunction with FLISR (see

[75] *See* https://www.energy.gov/sites/prod/files/2016/10/f33/Distribution_Reliability_Report_-_Final_Dec_2012.pdf

Section 1.8). A 26% SAIFI improvement was used as an input in the interruption Cost Estimator (ICE) calculator[76] for the BCA benefit calculation.

Microprocessor Relay Upgrades

Substation relays provide the logic inside a substation for when and why a breaker opens. Modern relays are multi-functional and have multiple protection functions programmed into them. The Foundational Investment for relays is based on replacing or re-programming over 400 relays. The investment also includes dollars for engineering of substation rebuilds. The primary use-case for a relay on a feeder breaker is to monitor the status of the distribution system and trigger an open command to the breaker in the event of a fault on the system. These relays can also capture important fault information which will be sent to ADMS for the Fault Location application. Replacing the existing and obsolete electro-mechanical relays on each distribution feeder with microprocessor relays will add significant additional sensing data to the ADMS system to improve visibility and situational awareness. Significant swings in loading and the prevalence of two-way power flows caused by renewable DG will require more adaptive relay protection schemes to properly coordinate circuit breakers to ensure worker safety and the reliable operation of the grid.

Traditional distribution protection schemes with electro-mechanical relays utilize phase and/or ground overcurrent relays to detect short-circuit faults. Coordination is achieved through time-delayed operation. While this is a proven and effective method for clearing "traditional" fault types, such as a solid tree contact, it leaves gaps for restricted faults, such as a downed conductor – critical to public and worker safety, and arc flash protection, DER and ride-through coordination for bulk system stability, and general customer experience via voltage dips (brown outs) or interruptions to service. The goal of advanced protection schemes at Rhode Island Energy is to cover these gaps while also building toward a future where the grid is fully adaptive to system conditions, including protection schemes. There are near-term and future term capabilities, as follows:

Near-term:

These are benefits achieved at PPL, which will be gained at Rhode Island Energy:

– *Downed-Conductor Detection:* PPL has utilized SEL's Arc Sense algorithm and built patented logic on top of it to build a system for automatic isolation of downed conductor events. The success rate at PPL is around 60%, with each event involving the public in close

[76] *See* https://icecalculator.com/home

proximity to the downed wire. Therefore, there is confidence that dozens of lives have been saved.

- *Worker Safety:* PPL utilizes hot-line tag ("HLT") on all distribution devices to protect workers from arc flash conditions as described in OSHA 1910.269. This involves instantaneous clearing and no reclosing to limit arc flash to the minimum incident energy. Since this was activated in 2016 there have been three PPL incidents where workers were subjected to flashes and serious injury was avoided with HLT activated.

- *DER and Ride-Through:* As the grid transitions into a distributed energy future, inertia in the system is reduced (i.e., fewer spinning generating units). It is therefore important for DER to remain online as long as possible during system disturbances to promote bulk power stability. Rhode Island Energy will establish ride-through DER settings balancing local system and system interests. If ride-through philosophies change over time, updated ride-through settings can be installed remotely.

- *Local Fuse Savings*: Traditional fuse savings schemes happen on 3-phase devise and impact hundreds or thousands of customers. Rhode Island Energy will work toward eliminating the 3-phase schemes and moving to local fuse savings via TripSavers at the head of single-phase taps. This improves SAIFI reliability by allowing for more downstream fusing of the taps. It also vastly reduces MAIFI by reducing the number of customers impacted by 90% (only the tap trips to save the fuse instead of the 3-phase device). This has the added benefit of minimizing effect of brown outs by clearing fault locally and as quickly as possible.

Future-Term:

Adaptive Protection: ADMS software that will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices to ensure worker safety and the reliable operation of the grid. This is a long-term project still in progress, but involves building an automated ADMS system that can adapt protection settings to changing system conditions. This application would automatically check if protective devices can clear all faults anywhere on the feeder. The goal is to make sure protection can clear faults when a feeder is in an abnormal state due to switching. In addition, the application will check the device pair coordination of all protective devices on a feeder based on protection settings and identify miscoordination. If there is a violation, it would check the alternate setting groups to see if another setting would provide coordination. This requires the relay and recloser settings to be defined in the ADMS database along with the alternate settings. The protection settings (e.g., fuse curves) would also be imported into the ADMS data. This first phase of the ADMS adaptive protection functionality is planned to be available in 2027 and the second phase is scheduled in 2029. Without GMP investments in ADMS, Advanced Field Devices, Microprocessor Relays, and an ADMS-based Protection & Arc Flash App, a labor-intensive process to make the system safe for workers would be required, especially under high DER adoption scenarios. In cases where DER could create protection system coordination issues or negatively affect arc flash levels, field crews would need to be dispatched to reprogram protection devices, rearrange the system, or even disconnect DER at certain times for safety reasons.

Dynamic Line Ratings: ADMS can use real-time weather conditions such as temperature and wind to increase line ratings which can improve line operation capabilities. Dynamic line rating can benefit renewable operators because rather than being asked to curtail at times of peak production due to congestion, if the peak coincides with windy or cold conditions, they could continue to produce if the conductor capacity ratings can be increased to carry the production because of conductions are cooler than originally assumed.

To implement the relay upgrades, a relay inventory was completed. Relays to be upgraded in the Foundational Investments represent approximately 17% of the total population. As a result, there will be ongoing relay upgrades performed in the future-term as well, both opportunistically and on a planned basis to achieve the desired operations for safe and reliable service. Efforts are underway to compare PPL protection philosophy with practices in Rhode Island and to apply PPL reference standards to the extent applicable. Preliminarily, Rhode Island Energy equipment looks similar to that used in other PPL jurisdictions; however, programming is very different and will require significant upgrades to integrate with ADMS FLISR approach for Reliability Management in Rhode Island. Alignment with FLISR and ADMS requirements and the emerging need of protecting equipment encountering multi-directional power flow is driving the urgency for having the microprocessor relay upgrades in the Foundational Investments.

6.5 GMP Roadmap: Communications

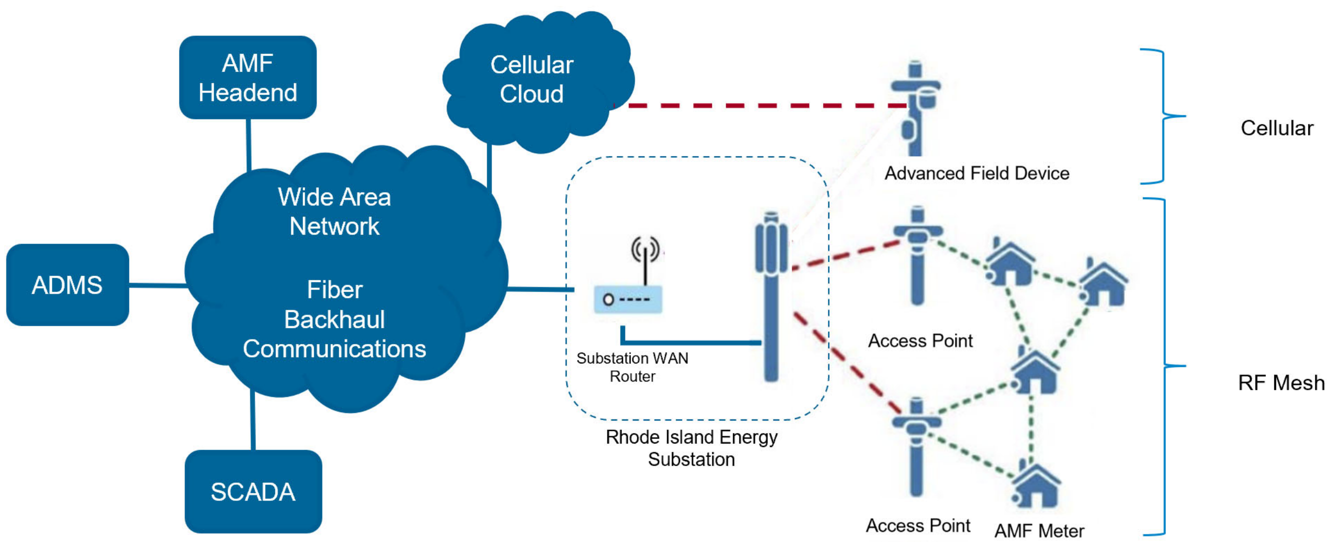
Rhode Island Energy is developing a communications network that includes a Fiber Backhaul in the Foundational Investments. The estimated cost of this investment is presented in Figure 6.21.

Figure 6.21: Foundational Investments Communications (Fiber)

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total Distribution Fiber Cash Flow	$ 8,270,000	$ 11,580,000	$ 18,240,000	$ 15,590,000	$ 8,160,000	$ 8,160,000	**$ 70,000,000**
Transmission Fiber	$ 3,285,714	$ 4,380,952	$ 7,666,667	$ 7,666,667	$ -	$ -	**$ 23,000,000**
Total Communications (Fiber)	$ 11,555,714	$ 15,960,952	$ 25,906,667	$ 23,256,667	$ 8,160,000	$ 8,160,000	**$ 93,000,000**

The communications network consists of the capability to simultaneously access diverse types of endpoints on the electric system - each with their own performance requirements. The strategy provides a two-way communication network that serves multiple “tenants,” which include but are not limited to, ADMS, FLISR, VVO, DER Monitor/Manage, and AMF – with potential for future applications such as natural gas sensors that are installed or upgraded with communications modules. The communications capability is achieved with several components, including but not limited to, the Company-owned wireless RF communications network that the Company proposed in its AMF Business Case in Docket No. 22-49-EL, leased cellular communications to the Advanced Field Devices, and a fiber backhaul communication system with substation interfacing infrastructure. Collectively these securely and reliably address the additional communication capacity requirements for electric distribution system advancements. Its primary function will be to enable secure and efficient two-way communication of information and data between the Rhode Island ADMS and other head-end IT systems with new or planned intelligent advanced field devices - up to and including AMF meters at customers' homes as shown in Figure 6.22.

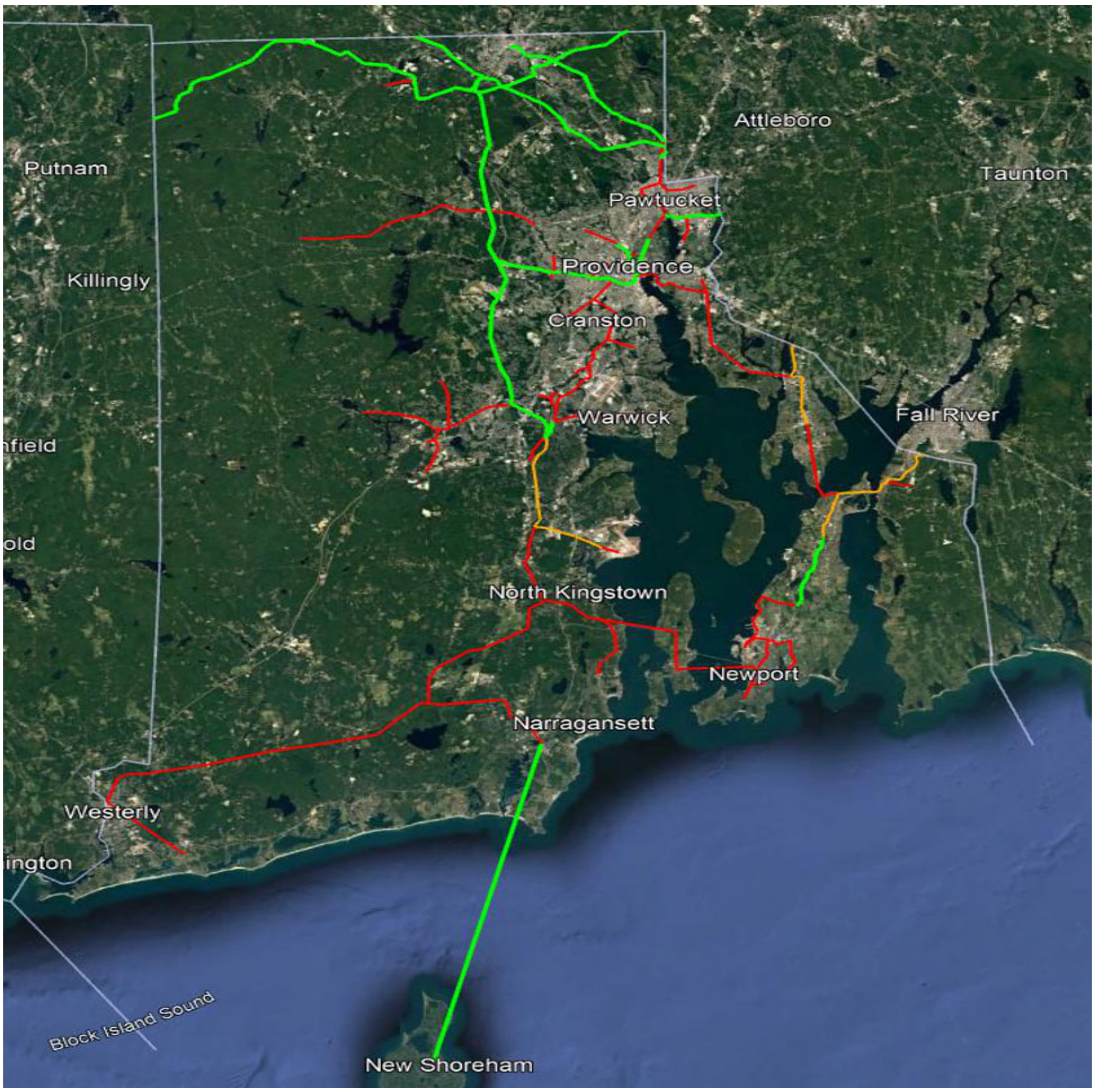
Figure 6.22: Communication System with Fiber Backhaul



For the proposed GMP initiatives to operate appropriately, the existing rudimentary analog communications must first be upgraded to current technologies that support the new requirements for increased network performance, security, reliability, and control. This is being achieved by bringing backhaul communications network in-house with a Company-owned fiber network where flexibility is improved with greater data bandwidth and communication speed. Also, there is added resiliency and the opportunity to enhance security provisions to mitigation against cyber threats. A private fiber network allows the Company to better control the integrity of the network and the data exchanged with field devices, which is important for reliability. Fiber provides high data rates without the risk of electromagnetic or radio frequency interference ("EMI/RFI") and longer distances can be achieved compared to what is possible with copper wires.

Eliminating the heavy reliance of commercial telecommunications carriers' antiquated analog technology is a major priority in updating communications to substations across the State of Rhode Island. Fiber will be extended to all Rhode Island Energy distribution substations, and a Rhode Island Energy-owned fiber loop will be developed for redundancy that connects each substation. This technology is needed to accommodate the vast quantity of operational data required for grid modernization and AMF. The network will provide security, speed, and bandwidth to achieve the required functionality and to achieve cost-effective benefits. The backhaul fiber network will consist of 100 miles of fiber expansion as shown in Figure 6.23. On this graphic, the green lines represent existing fiber, and the red lines represent fiber that will be installed. This is a shared facility between bulk Transmission and Distribution where 92 miles of distribution and 8 miles across water are included in the Foundational Investments. The remaining 46 miles of fiber for Transmission will be proposed through NEPOOL because it is a looped facility, where costs will be shared across the members. Rhode Island Energy's portion of this cost would be approximately 7% of the $23M because it is defined as a Pool Transmission Facility ("PTF"), based upon Rhode Island's load ratio share. The deployment of this network will reduce Rhode Island Energy's annual O&M costs. The cost and benefits of the Rhode Island Energy GMP fiber network are included in the BCA analysis – Section 8.

Figure 6.23: Fiber Backhaul Plan



6.6 GMP Roadmap: Other Future Solutions

Future-Term:

Energy Storage: The Grid Modernization Alternative identified in the Distribution Study assumes that there is capability to facilitate load shifting from high demand periods to negative load (i.e., periods of excessive renewable DG generation) by enabling flexible demand. Examples of longer-term flexible demand include EV charging, stationary energy storage, and perhaps, in the future, electric vehicle-to-grid charging/discharging, all of which are possible future-term customer-side resources. These demand loads are particularly flexible when customer DR programs and AMF with TVR are used to target both peak load reduction and "negative load filling." For example, load shift capability provided byAMF with TVR could enable customers to respond to price signals by reducing energy use during on-peak demand periods and increasing energy use during negative load periods. This shifting of energy consumption between time periods can reduce customer energy costs and maximize renewable generation utilization. The vision is for energy storage and/or EV charging to have automated controls in the future that can be optimized, initiating when to operate, initiating charging when prices are low, and then, in the case of the storage system, discharging when prices are high.

This GMP Roadmap assumes that this capability is future-term and it is not included in the Foundational Investments. That being said, the Distribution Study did include storage as a solution where the application of it is needed starting in 2029. According to the Distribution Study, by 2030, there are 211 days that the system needs storage at least an hour a day in the calendar year. Batteries are used to fill in the valleys with demand and shave the peak. In this era, about 600 MWh of energy storage will be needed across the system to be used, worst case. Half of this is forecasted for deployment in 2029 and the other half in 2030.

Figure 6.24: Battery Storage Needs

Batteries		
Year	MWh Capacity	
	Incremental	Cumulative
2030	608.0	608.0
2040	327.0	935.0
2050	280.0	1,215.0

Electric Vehicle Charging and Vehicle to Grid

Acceleration enabled by the Foundational Investments is needed in the near-term to be prepared to optimize with these flexible assets. TVR has been forecasted as a near-term functionality. Long-term is using the charging infrastructure and vehicle to grid capabilities for increased flexibility. Capabilities such as TVR, DER Monitor/Manage, ADMS and more are needed to fully capitalize on this opportunity. According to market forecasts, behind-the-meter energy storage in the U.S. is projected to increase from 1 gigawatt in 2020 to 7 gigawatts in 2025.[77] About 1.8 million EVs have been sold in the U.S. as of February 2021, representing about 4.5 terawatt-hours of movable, annual load.[78] EV registrations are projected to increase to 5.6 million by 2025.[79] So, while these solutions are categorized as future-term, they are clearly in the line of sight of plausibility making it important for the Company to invest now to prepare for the value that they can offer Rhode Island customers, Rhode Island Energy and advances to achieve the Climate Mandate.

6.7 Critically Linked Aspects of AMF and GMP

AMF near-term functionalities, available upon deployment of AMF meters, are foundational[80] to achieving three key grid modernization functionalities and provide significant enhancements to six others, allowing for better observability, planning, and control of the distribution system and DER. The following Table 6.25 is a brief summary of how AMF near-term functionalities are important enablers for most of the key GMP functionalities. See the AMF Business Case Section 4 for more discussion on the AMF-enabled functionalities.

Figure 6.25: AMF Functionalities & Impact on Rhode Island Energy GMP Functionalities

RI GMP Key Functionality	AMF Near Term Enabling Functionality	AMF Impact on GMP Functionality
Customer Information	CP, GBC, Integration w/ In-Home Technologies	Foundational
Advanced Pricing	Interval Energy Usage Data	Foundational
Remote Metering	Remote Interval Meter Reading, Remote Connect & Disconnect	Foundational

[77] Wood Mackenzie, energy storage forecast data tool. Note: Behind-the-meter storage includes power capacity in the residential, commercial, industrial, education, military, and nonprofit segments.
[78] EPRI "Maximizing Distributed Energy Resource Value Through Grid Modernization" 2021.
[79] *Id.*.
[80] Foundational means the GMP functionality would not be possible without AMF.

Observability (Monitoring & Sensing)	Load & Voltage Data	Enhancement
Power Quality Management	Load & Voltage Data	Enhancement
Distribution Grid Control	Load & Voltage Data	Enhancement
Grid Optimization	Load & Voltage Data	Enhancement
Reliability Management	Automated Outage & Restoration Notification, Granular Fault Location	Enhancement
DER Monitor/Manage	Remote Interval Meter Reading, Load & Voltage Data, Telecommunications	Enhancement Foundational

Further detail related to AMF impacts on GMP functionalities is included below and expanded upon in Section 4 of the AMF filing:

- **Customer Information:** AMF provides access to timely, granular energy usage information for all customer classes through three primary channels: 1) web and mobile devices via the Customer Portal 2) data sharing using Green Button Connect that will be available on the Customer Portal and 3) directly from the meter in real-time through a home-area-network (HAN). AMF also empowers customers to reduce their energy costs using enhanced insights (such as high bill alerts) on more granular, timely energy usage data through the CEMP or using integration with the HAN.

- **Advanced Pricing:** AMF provides interval energy usage information required to support TVR and customer load management programs that can be used to shift energy consumption between time periods to reduce energy costs and/or alleviate location specific constraints on the delivery system. This will ultimately enable efficient Smart EV Charging and battery storage for customers and the utility.

- **Remote Metering:** AMF improves operational efficiency by enabling the Company to eliminate O&M costs associated with AMR meter reading, investigations, and visits to connect and disconnect service.

- **Observability (Monitoring & Sensing):** AMF provides granular and timely customer load data to support actionable information on the operating state and condition of the distribution grid and DER assets necessary for safe, secure, and reliable operation. AMF information results in greater situational awareness that leads to improve operation and planning capability such as the anticipation of hidden load switching schemes, for example.

- **Power Quality (Voltage) Management:** An incremental 0.167% VVO/CVR-based reduction in peak demand by integrating granular AMF voltage data into the VVO control schemes. This data will provide better awareness of feeder voltages compared to only using voltage data for advanced field devices.

- **Distribution Grid Control:** Granular and timely customer load data from AMF supports more accurate load flow calculations, enabling the distribution system operator to better control power flows on the distribution system and optimize power output from renewable DER (through ADMS to relieve or avoid thermal or voltage constraints rather than investing in traditional solutions (e.g., reconductoring, substation upgrades).

- **Grid Optimization:** AMF provides granular, 15-minute interval load data customer metering, which provides a step-change in available data for grid planning and operations. Analytics of the AMF interval data will significantly improve the load flow models used by distribution planners. Today, feeder-level data combined with generic load shape analysis is used to model feeder performance. AMF provides more granular, timely values that can be aligned with other systems, such as PPL's ADMS to create actual loading and voltage profiles at all points along a feeder. More detailed load and DER forecasts can be developed for planning and operational needs.

- **Reliability Management:** AMF provides automatic outage notifications in the form of Last Gasps, alerting the Company to troubleshoot before receiving customer outage calls. Integrating this functionality with the Company's OMS (via PPL's ADMS) will reduce the time from initial outage to Company notification. In Pennsylvania, automatic notification has resulted in a 22-minute faster notification of customer outages on average. AMF also provides restoration notifications enabling the Company to verify whether power has been restored to all meters, reducing the need for crews to verify restoration (i.e., lights-on truck rolls) and alerting the Company if some meters are still out of power. In addition, AMF provides granular outage data at the customer level, increasing the accuracy of fault location capabilities of the PPL ADMS. More accurate fault location improves operational efficiency through a reduction in field crew hours and vehicle miles traveled, and it improves the isolation and restoration capabilities of FLISR.

- **DER Operational Control:** AMF supports DER optimization by providing the interval energy and voltage data at the customer level required for verification and settlement of DER services provided to or received from the grid. AMF also enables the exchange of information and/or control with all residential and small commercial (<25 kW) DER technologies through AMF's investment in a RF Mesh telecommunications system, which would not be possible without

AMF investment.[81] The use of this data by outside parties will be subject to the Data Governance Plan, which is included as Attachment G in the AMF Business Case filing.

[81] Currently, the Company requires a dedicated phone line, RTU, and interval meter for all distributed generation greater than 25 kW, but there are not meter requirements for systems smaller than 25 kW.

Section 7

SECTION 7: Risk Mitigation, Deployment, and Accountability

This Section provides an overview to the approach used to create the GMP that manages risks and uncertainties resulting in a no-regrets investment plan applicable to all future-state DER scenarios. Among the risk mitigation considerations described in this Section are Leveraging PPL experience, seeking stakeholder engagement and input, selecting solutions that are flexible, applying a Benefit-Cost Analysis with sensitivities, creating a deployment plan and providing data governance to address privacy and security risks. This Section also introduces the proposed review mechanism and recommended reporting metrics.

7.1 Managing Risks of Redundancy, Obsolescence, and Uncertainties

Developing a long-range grid modernization plan in a fast-changing environment requires acknowledgement of numerous uncertainties. A precise future state is difficult to predict due to the many factors that influence future demands on the distribution system, including future federal, state and local policies, regulations, and requirements; technology options and their costs; market maturity and barriers; and customer preferences. Key uncertainties associated with the GMP include: (i) the pace, scale and location of DER adoption; (ii) technological advancement; and (iii) the development of complementary programs and services to be leveraged in the management of the electric distribution grid. These uncertainties create many risks such as redundancy and obsolescence.

In recognition of these risks, the Company employed a wide range of methodologies when creating the GMP designed to manage them. The Company has engaged with the GMP/AMF Subcommittee, participated in grid modernization research and industry forums, evaluated multiple Rhode Island future state scenarios, leveraged industry standard designs, performed a BCA aligned to the Docket No. 4600 guidance that includes sensitivities, and developed a portfolio of Foundational Investments that are malleable and can be modified through future regulatory review based on actual DER adoption rates and system needs. This approach ensures that the Foundational Investments are “No Regrets” investments. The Company developed the GMP using industry standards and internal reference standards to drive predictability and scalability. It leverages experience and systems that have already been developed and implemented by PPL in its other jurisdictions, which mitigates technology and schedule uncertainty. This GMP proposes the latest generation technology, featuring over-the-air firmware upgrade capabilities, which are critical for futureproofing and maintaining a security system to keep devices up to date and to protect against new cyber vulnerabilities.

7.2 Grid Modernization Roadmap Approach

The GMP proposes a Grid Modernization Roadmap that is built with the Foundational Investments and can be expanded upon over the long-term to coincide with DER adoption rates. The Grid Modernization Roadmap achieves optimum value through integrated solutions, which is based upon a framework of standards.[82] For example, Advanced Field Devices to be deployed in conjunction with IT platforms, are flexible and scalable. The ADMS Basic will bring value immediately through its ability to perform FLISR and will expand in phases to bring incremental value such as VVO and adaptable protection. Rhode Island Energy will have the benefit of using systems and practices that have been applied earlier by PPL, which will reduce the time for development and increase confidence in the implementation and associated benefits. Further, phased-in ADMS development provides the ability to build upon prior success and align capability to emerging needs. The Grid Modernization Roadmap also incorporates the introduction of AMF granular data, in conjunction with the Company's pending proposal to install AMF smart meters throughout Rhode Island by 2026. By bringing together multiple streams of important data from Advanced Field Devices and AMF, situational awareness of system conditions are greatly enhanced because data is synthesized in a cogent way to provide real-time, relevant information in a single location, providing operators with system visibility. The clarity of system status will continue to improve as synthesized streams of data increase over time, thereby providing wherewithal to operate an increasingly complex system.

Maintaining a longer-term roadmap will foster stakeholder engagement, aid in identifying synergies between projects, ensure maximization of net benefits, and create efficiencies through standardization. Cost recovery requests for grid modernization investment will be made through annual ISR plans, which will provide the opportunity for annual assessment, review, and reporting.

7.3 "No-Regrets" Investment Needed for All Future State Scenarios

The Company has taken several steps to better understand these uncertainties and manage the risks associated with operating a system that is becoming increasingly complex and uncertain. Most notable, is the step to create the Distribution Study using a state-of-the-art, 8760-hour per year, load flow analysis to define the range of investments required to build and operate a safe and reliable modern-day grid that can achieve the Climate Mandates.

Based on the uncertainties described above, the Company performed its forecasting and planning around two alternatives that were described in Section 5. The GMP concludes that the proposed Foundational

[82] The Company will use its existing standard designs and equipment for near-term installations, and it will synchronize those standards with PPL reference standards to the extent possible and practicable given the unique characteristics of the legacy system. *See* Section 7.4. If standards changes are necessary, the Company will update them accordingly.

Investments which bring near-term grid modernization capability to Rhode Island are the least risk approach given the uncertainty of future states. As the Foundational Investments are being deployed, the Company will realize capability that is needed to operate the system toady and build the operational wherewithal to successfully operate given a wide range of uncertainties and dynamic conditions to achieve the Climate Mandates. The Foundational Investments provide the ability to monitor and identify grid challenges, such as voltage excursions, capacity constraints, hidden load, load and generation balance, and reliability metrics, to understand system conditions, operate accordingly and proactively address customer and system needs. System conditions vary widely today, depending upon location. Given the long lead times required for the planning, testing, and deployment of GMP investments, it is important for the Company to have system visibility in order to anticipate and apply solutions in a timeframe that addresses locational system needs to maintain safety and reliability.

Evaluating the scenarios at the level of granularity enabled by the 8760-hour analysis allows the Company to understand the system's long-term needs and also provides insight as to the emergence and progression of the needs. This allows the Company to implement a more sequenced and flexible GMP that avoids redundancy from unanticipated re-work that can easily occur without having the benefit of a long-range granular system view that is forward looking, provided by the comprehensive Distribution Study.

7.4 PPL Insights and Experience

Grid modernization is complex, requiring careful planning, product selection, integration, and execution. PPL is an innovator, industry leader and early adopter of grid modernization. Rhode Island customers can benefit from PPL's expertise and the functionality it already has developed. For example, PPL has researched, identified, designed, implemented, and integrated the necessary and critical back-office systems and infrastructure to maximize the benefits of AMF meters for its customers and stakeholders. This has resulted in functionality that provides a wide range of benefits improving safety, reliability, cost, and ultimately customer satisfaction. Examples of the major platforms that PPL has deployed and integrated in Pennsylvania include: (i) Customer Information System; (ii) Billing/Settlements Systems; (iii) ADMS; (iv) DERMS; (v) OMS; and (vi) Data Analytics, among many others. These PPL platforms, systems, and expertise will be available to Rhode Island Energy – greatly improving the efficiency of implementation and providing value to Rhode Island consumers with the planned and purposeful rollout of the GMP. Additionally, PPL's IT technology platforms such as ADMS, DERMS, Transmission Management System ("TMS"), SCADA, and modeling and control operations for the entire PPL transmission and distribution grid already are interconnected to PPL's GIS model and fully integrated with granular AMF meter information. PPL can import Rhode Island Energy data and thereby leverage many of these existing systems and integration efforts to rapidly bring operational capability and cost benefits to Rhode Island Energy customers.

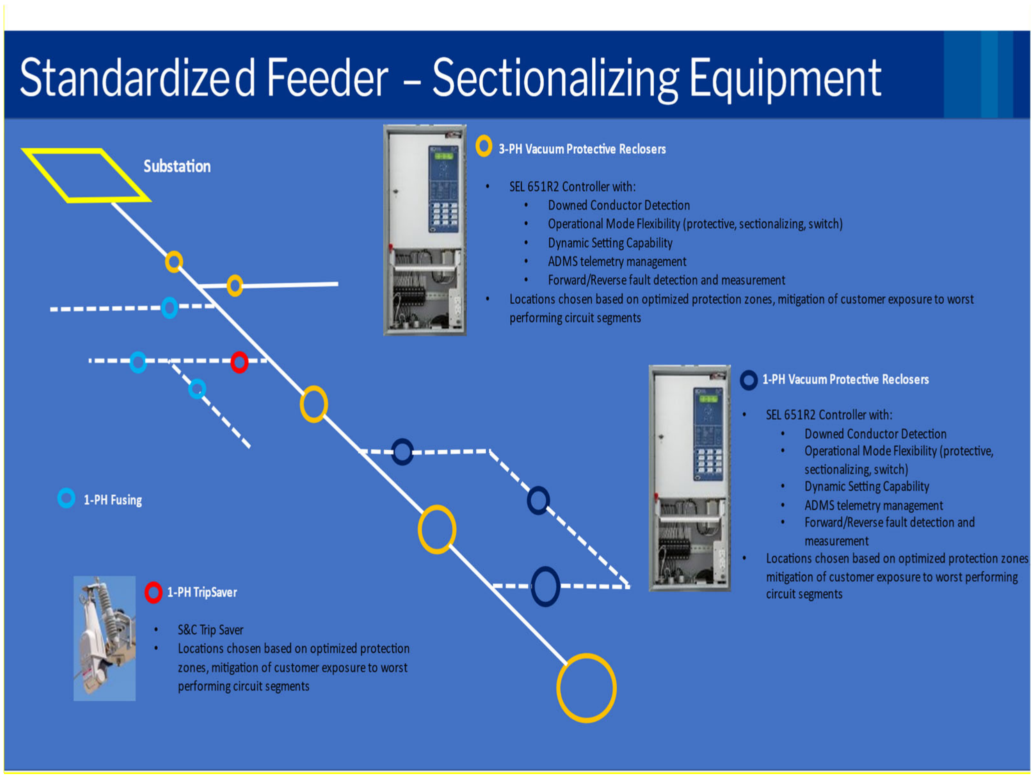
To address grid challenges from DER penetration, PPL Electric filed a petition with the Pennsylvania Public Utility Commission for permission to require smart inverters that meet the new IEEE and Underwriters Laboratories ("UL") standards to install DER management devices on new DER interconnected with its distribution system, and to monitor and manage those new DER. Since January 2021, PPL Electric has been implementing its program to test and evaluate costs and benefits of both monitoring and actively managing inverter-based DER. PPL Electric will evaluate the benefits that DER management may provide, including improved safety, reliability, power quality, stability of distribution grid operations, and greater adoption of DER across its service area at a lower cost to customers. See Attachment G for more information and background on DER Monitor/Manage and the importance of it to this GMP.

7.5 Leveraging Industry Standards and Flexible Designs

Rhode Island Energy, with its counterparts throughout PPL, is actively engaged in shaping grid modernization activities within the industry, including ongoing work with IEEE, Electric Power Research Institute, Inc. ("EPRI"), SEPA, and DOE. The Company has taken what it has learned from these industry engagements to shape this GMP. In addition, the Company proactively explores new technology opportunities through industry events such as DistribuTECH, IEEE Power and Energy Society Transmission and Distribution (T&D) conferences and frequent engagements with vendors. As promising technologies are identified, the Company assesses the new equipment and explores its viability for inclusion within its Distribution Standards so that it may be safely, reliably and cost effectively deployed and integrated within grid operations.

PPL has introduced reference standards that are aspirational in nature to provide guidance for consistent design standards across jurisdictions. The purpose of the reference standards are to improve reliability and safety, standardize the protection strategy, and lower O&M costs. These reference standards guide the implementation of the GMP and the future expansion of the Rhode Island Energy T/D system. For example, Figure 7.1 below illustrates the reference feeder design.

Figure 7.1: PPL Reference Feeder



The reference feeder is planned, designed, and constructed to: (i) optimize reliability and resiliency; (ii) reduce maintenance costs; (iii) provide real-time visibility and situational awareness; and (iv) to adjust dynamically for load, contingencies, and DER changes. Standardizing grid modernization system architecture, protection philosophy, and devices that are included in the GMP (i.e. advanced capacitors, regulators, reclosers and their advanced controllers and telecommunications radios) allows for cost effective design, integration, procurement and personnel training. For similar reasons, the Company also seeks to leverage common platforms and information management to the extent possible. For example, the Company's control center applications for ADMS and related operational systems will share a common platform where the GIS model will be the basis for load flow modeling for both planning and operations.

7.6 Benefit-Cost Analysis

To evaluate the cost effectiveness of the grid modernization portfolio of investments, considering the system impacts that may arise over the range of the future state scenarios, the Company has developed a quantitative BCA for the GMP that is aligned with Docket No. 4600 Guidance. It goes without saying that the costs and benefits used in the BCA are not known with complete certainty. Therefore, sensitivities for both costs and benefits were performed within the BCA analysis in Section 8. The sensitivities provide clarity for GMP decision making because the evaluation contemplates the impact of a range of uncertainties and risks on the BCA to provide an understanding of how a GMP decision could be impacted by them.

7.7 Deployment Plan Approach

The GMP Deployment Plan will leapfrog Rhode Island Energy to a state-of-the-art electric distribution grid that delivers choice and improved reliability for Rhode Island customers, the achievement of goals in accordance with the State's Climate Mandates, and the transition to a modern-day grid that distribution system operators can manage effectively and efficiently. As such, the GMP Deployment Plan necessitates a strong project management methodology and structure to ensure successful execution and project outcomes.

The detailed GMP Deployment Plan is captured in Attachment H of this GMP. It provides a summary of the approach, supply chain/vendors, project governance, and the GMP solutions portfolio, followed by another level of detail of each of the various GMP solutions – background, objectives, benefits, deployment priorities and a schedule. It references the AMF Business Case that was filed separately in November of 2022 and then describes the GMP solutions in much greater detail.

7.8 Data Governance, Data Privacy and Cybersecurity in the IT Solution

Data Governance, data privacy and cyber security are critical to managing the distribution system more granularly to meet customers' evolving expectations reliably, safely, and cost-effectively and provide them with greater choice and control in addressing their energy needs. Cyber and privacy threats may emerge as new, grid connected technologies are introduced. Monitoring and control capabilities must include cyber security solutions in the process rather than as a retrofit or afterthought.

Recognizing the need to maintain and enhance an in-depth cyber security plan to prevent and mitigate ever-changing cyber threats and address privacy, the Company has developed pertinent policies addressing data privacy, data governance, information classification, cyber security, and enterprise security standards. Through these policies and standards, the Company seeks to provide standard information security practices to safeguard the privacy of personal and critical system information effectively and consistently while also supporting its critical infrastructure and vital business functions, including GMP. The Company's commitment to stewarding data is memorialized through its

Cybersecurity, Privacy and Data Governance Plan ("Data Governance Plan") in Attachment J,[83] which includes provisions for making data accessible while keeping it secure and maintaining customers' privacy.

The Data Governance Plan, also submitted in the AMF filing, exists to ensure the data generated by the Company is collected, managed, stored, transferred, and protected in a way that preserves privacy, and is consistent with cybersecurity requirements, as well as grid modernization objectives and the Climate Mandates. It provides a framework of corporate policies that have been developed to ensure the management, protection, and secure availability of the Company's data and information assets is appropriate and maintained. The policy is built on risk-based cybersecurity framework components that include a comprehensive set of principles and standards, requiring regular assessments and constant vigilance using an approach that tracks across people, process and technology. Furthermore, the Data Governance Plan defines the organizational commitment to having enterprise-wide operational processes that provide a robust security environment. The Data Governance Policy, one of several policies that support the Data Governance Plan, further defines the roles and responsibilities for different data creation and usage types, and maps clear lines of accountability. It also develops best practices for effective data management and protection, ensuring that a process is in place to comply with applicable laws, regulations, exchange, and standards and establishes a mechanism to ensure that a data trail for vulnerabilities, threats and complaints is effectively documented and managed.

To ensure emerging security and privacy risks are identified and adequately addressed, the Company is committed to using the cyber security materials that were discussed in Section 2.3 and a process that identifies vulnerabilities by conducting an initial privacy and security impact assessment as part of the Foundational Investments. The approach for the impact assessment is defined by NISTIR 7628 Guidelines for Smart Grid Cyber Security. The assessment compares the NIST Guidelines to the Company's existing privacy policies, procedures and the GMP to identify where best practices are in place or where additional alignment is needed given the emerging security and privacy challenges that are presented by GMP investments in the near-term and vulnerabilities that may surface in the future-term. Acting with the privacy impact assessment demonstrates that the Company understands that grid modernization technologies bring new types of information that can involve security and privacy and is evidence of the Company's commitment to the Data Governance Plan. Manufacturers and vendors of various aspects of the modernized electric distribution system will be expected to engineer and operate to collect and limit the use of the data to only that necessary for purposes of grid modernization. Investing in cyber security helps the Company avoid several risks that may impact grid stability, which includes avoiding wide-scale blackouts. In addition, investing in data security will help the Company

[83] PPL's Cybersecurity, Data Privacy, and Data Governance Plan ("Data Governance Plan") provides a framework that includes a comprehensive set of principles and standards that address cybersecurity, data privacy, data governance, information classification, and enterprise security standards for PPL Corporation and its affiliates and subsidiaries ("Company"). Where the policy references "AMF", it will equally apply to investments that are a part of the GMP.

better protect distribution system and customers' personal data. Examples of the considerations include: 1) protection of computer systems from theft or damage to the hardware, software or the information on them; 2) controlling physical access to the hardware; 3) protecting against harm that may come via network access, data and code injection; and 4) harm due to malpractice by operators or due to deviation from secure procedures.

7.9 Annual ISR Plan Reviews

This GMP serves to align future ISR plan proposals with the overarching grid modernization functions and goals to avoid obsolescence and redundancy. As the Company advances projects, it will do so in a comprehensive manner considering the other programs and projects within the ISR plans. For example, grid modernization efforts in any area need to be closely aligned with the ADMS, VVO/CVR, and FLISR programs that may be a part of the ISR plan. Specifically, substation and telecommunications efforts would be coordinated to gain efficiencies. In this manner, the Company can demonstrate that its proposals are efficient considering the state of the system at the time of proposal. The Company also can ensure that its proposals are as aligned as reasonably possible with a variety of future states. The Company will continue to analyze the evolving electric distribution system and adjust the grid modernization investment proposals as necessary.

7.10 Reporting Metrics

The Company proposes to monitor and report on metrics on an annual basis throughout the horizon of the GMP to ensure timely and effective solutions are deployed and benefits realized. The Company anticipates reporting on the following metrics as discussed below:

DER Metrics: The scale and timing of the deployment of many of the grid modernization investments will be informed by the actual pace of DER penetration over time and DER related policies and programs. The Company plans to monitor the following metrics on an annual basis so that it can modify the nature and pace of grid modernization investments appropriately to the evolving environment.

DER Interconnections (installed and in queue)

- Wind DG (nameplate kW)
- Solar DG (nameplate kW)
- Energy Storage (nameplate kW)
- EHP Heating Demand (peak load kW)
- EV Charging Demand (peak load kW)

Dispatchable DR (available kW and kWh registered and number of dispatch events)
- Customer DR Programs (i.e., residential, C&I)
- NWA Projects (e.g., company-owned or contracted third-party DER)
- Energy Storage (i.e., customer solutions through customer DR programs, NWA, or other means)

Deployment Metrics: In order to ensure grid modernization solutions are deployed according to plan, the Company plans to track the deployment progress of GMP investments by monitoring the following metrics on an annual basis for the Foundational Investments:

- Advanced Field Devices: number of devices installed and in-service, number of feeders covered, cost for deployment, deviation between actual and planned deployment
  - Advanced Capacitors & Regulators
  - Advanced Reclosers
  - Electromechanical Relay Upgrades
- Operational Systems and Applications
  - ADMS Functionality
  - Underlying IT Infrastructure
  - DER Monitor/Manage
  - Mobile Dispatch
- Communications: number of communication devices, or nodes, or miles of fiber installed; cost for deployment; deviation between actual and planned deployment

Performance Metrics: In order to determine if expected grid modernization benefits are being realized, the Company plans to track the performance by monitoring the following metrics on an annual basis during the first six years when the Foundational Investments[84] are being made:

System-Level Impacts
- Peak Loading (MW, date, time)
- Minimum Loading (MW, date, time)
- Load Factor (average/peak)
- Load Range (peak – minimum)

Modular Optimizing Applications
- VVO/CVR: energy savings, peak demand savings, loss reduction, power factor improvement

[84] GMP assumes the availability of AMF granular data. See AMF Business Case for AMF Reporting meters.

- FLISR: number of FLISR operations, effect on outage frequency (SAIFI change before and after FLISR commissioning)
- DERMS: number of interconnections with capability, capacity factor improvement, curtailment

7.11 Complementary and Supporting Polices, Regulations, and Requirements

The effectiveness of the GMP and the pace and scale of its implementation will be impacted by the evolution of future policies, regulations, and requirements. Although the development of these future policies, regulations, and requirements is beyond the scope of the GMP, assumptions concerning their future authorization are inherent in the GMP roadmap and associated BCA.

The following potential future policies, regulations, and requirements are expected to impact the evolution of the GMP:

- **TVR**: The GMP envisions that TVR will be a primary driver of load shifting through customer load management programs.[85] The AMF Business Case includes the Company's intent to file a TVR proposal to become effective after AMF meters are installed. As customers become accustomed to TVR, more advanced rates that better align price signals to electricity costs can be implemented to help shift customer demand away from higher cost periods of time.[86] The proposed AMF meters have interval metering and the ability to perform over the air software and firmware updates to allow re-programming as needed. Therefore, any expansion or changes to TVR can occur without requiring the meter to be replaced. The GMP will identify anticipated distribution system constraints which will be reflected in TVR pricing as an incremental value proposition to further incent TVR participation and load shifting behavior beyond what could be done with AMF alone.

- **DG Tariffs, Flexible Interconnection Standards, and Distribution System Operating Requirements**: The GMP envisions that some combination of an expanded DG interconnection tariff with some level of flexibility on how DG can or should operate, and/or operating requirements for grid injections from DG and energy storage will be necessary to optimize DER output for the benefit of the electric distribution system, customers, DER developers, and society. Current practices whereby DER are not dispatchable will be problematic at high DER penetration levels, and future policies and regulations on the interconnection tariff and operating requirements will require consideration of how best to leverage these technologies. It should be

[85] Customer load management programs are defined here as customer-facing programs that can be used by distribution planners and operators to better manage the distribution system to achieve compliance or optimization goals.
[86] "More advanced rates" may reference mechanisms such as Real Time Pricing, residential demand charges, and others discussed in Attachment C of the Updated AMF Business Case.

noted that the same reprogrammable and interval AMF meters being proposed for rate-paying customers will also be used for most DER customers. Therefore, any expansion or changes to the DG tariff could occur without requiring the DER meter to be replaced. In addition, the use of raw interval data can be manipulated by the AMF meter data management system (MDMS) to allow for numerous billing scenarios, including time varying rates.

- **DER Monitor/Manage of Smart Inverters using IEEE 1547-2018:** The variable nature of many DER, especially distributed solar and wind generation, presents voltage and frequency challenges on the electric grid. One promising technical solution to help address these challenges is so-called "smart inverters." Unlike traditional inverters that are designed to run at unity power factor, smart inverters can absorb and generate reactive power to help reduce fluctuations in the output voltage of the facility as well as help manage voltage on the distribution system. With DER Monitor/Manage, smart inverters can also reduce DER output power generation at times to avoid escalating system conditions (i.e., over-frequency conditions) and can respond to power curtailment commands. The Foundational Investments included DER Monitor/Manage using the ADMS-DERMS application to exercise DER management to avoid grid voltage and capacity violations and to provide grid stability by having the control to balance load and generation. The Company has included DER Monitor/Manage in the GMP, which will require the use of UL certified smart inverters using the IEEE 1547-2018 interconnection standard. The Company is assessing the legal and regulatory approvals necessary to permit DER Monitor/Manage and will make a separate filing for such approvals, including any tariff changes. Additional details are presented in Attachment G.

7.12 Periodic Rate Case Authorizations

Investments included in the ISR are generally limited to Company's capital investments. PPL is extending advanced grid technologies and processes for Rhode Island – this includes General Electric's transmission and distribution SCADA and operations systems and a dynamic line rating process to improve the performance and capacity of transmission lines. Where existing PPL Services Corporation systems will be used, those are being reviewed and expanded as needed to support the Company. The cost recovery of for these and other expenses generally will be presented in periodic, multi-year rate case proceedings and more details on these proposals will be presented at that time.

Section 8

SECTION 8: BCA Evaluation Under Docket No. 4600

This Section presents the GMP BCA approach and results including Docket 4600 alignment, cost contingencies, benefits by operations, customer and societal breakdown, and a cost-benefit sensitivitv analvsis.

8.1 Introduction, Approach, and Summary Results

Introduction

The purpose of the BCA is to demonstrate the benefits and costs of implementing GMP Foundational Investments across the Rhode Island Energy service territory. The Foundational Investments are near-term solutions in the GMP roadmap, which are generally installed by 2028. The resulting platform can be built upon with future-term investments thereafter. In the BCA, benefits and expenses were included for the Foundational Investments and for DER Monitor/Manage installations forecasted through the 20-year period as well as the run-the-business ("RTB") costs including RTB OPEX and RTB telecom.

Not only are the investments proposed in the GMP critical for reliability and safety, but the overall results are significantly positive from a BCA perspective using the Docket 4600 Framework. Furthermore, the reliability and safety, customer, operational, clean energy, and financial benefits justify immediate deployment.

Approach

The GMP BCA uses the Docket 4600 Frame work to identify where grid modernization solutions contribute to specific cost or benefit categories. Where possible, these benefits are quantified. In cases where benefits cannot be quantified either due to lack of data or lack of an accepted method, the Company conducted a qualitative analysis of the benefits, consistent with the Docket No. 4600 Framework.

The Company made use of the assumptions, logic, and findings in the National Grid 2021 BCA (Docket No. 5114). The Company updated the assumptions, cost, and benefit calculations and performed a leading-edge, comprehensive Distribution Study to determine the avoided infrastructure cost and DER curtailment benefits of the grid modernization investments (see Section 5.0).

Due to the significant customer benefits enabled by AMF, and because the Company has a separate AMF filing, two separate but consistent, quantitative BCA models were developed: 1) AMF BCA model (used in the AMF filing) and 2) GMP BCA model. The GMP BCA model assumptions and results are described in detail in this section and the AMF BCA is described in detail in Rhode Island

Energy's AMF Business Case filing. The following key assumptions are used in the base case BCAs for both the GMP and AMF:

- Nominal Discount Rate = 6.97% (After-Tax WACC)
- Labor Escalation = 2.5%
- Non-Labor Escalation = 2.3%
- AESC Escalation = 2.0%
- Societal Discount Rate = 3.0%
- AESC Discount Rate = 2.0%.

The GMP and AMF BCA models used a consistent approach and input assumptions. The detailed BCA assumptions and results presented in this section are focused on the GMP BCA model.

Summary Results

As shown in Figure 8.1, over a 20-year evaluation period, Rhode Island Energy expects to invest $529 million Nominal and $373.8 million on a $2023 Net Present Value ("NPV") basis. Over the 20-year life of the GMP Foundational Investments, Rhode Island Energy expects Rhode Island utility benefits, customer benefits and societal benefits of $3.9 billion Nominal and $2.5 billion NPV-$2023. This results in a net value of benefits minus costs of $3.4 billion Nominal and $2.2 billion NPV-$2023. The benefit/cost ratios are 7.5 Nominal and 6.8 NPV.

Figure 8.1: GMP Benefits and Costs

GMP Benefits and Costs				
As of December 22, 2022				
Category	**Nominal ($M)**		**NPV ($M)**	
Utility	**$**	**2,928.8**	**$**	**1,768.6**
Direct Customer	**$**	**527.7**	**$**	**377.1**
Societal	**$**	**490.4**	**$**	**379.1**
Total Benefits	**$**	**3,946.9**	**$**	**2,524.7**
Total Costs	**$**	**529.0**	**$**	**373.8**
Benefits Less Costs	**$**	**3,417.8**	**$**	**2,151.0**
B/C Ratio	**7.5**		**6.8**	

For ease of understanding, Rhode Island Energy also sorted the benefits into categories reflecting the source of the benefits. These categories include:

- Avoided Infrastructure Costs.
- Reduced DER Curtailment.
- VVO/CVR Benefits.
- Reduced Outage Frequency Benefits.
- Whole House Time-of-Use/Critical Peak Pricing (TOU/CPP).
- Electric Vehicle Time Varying Rates Benefits (EV TVR).
- Utility O&M Savings.

Figure 8.2 depicts the benefits by category on both a nominal and NPV ($2023) basis. As provided in the chart, there are significant benefits in every category with Avoided Infrastructure Costs being the greatest at $1.1 billion, Reduced DER Curtailment (energy only) at $0.84 billion and VVO/CVR Benefits at approximately $0.75 billion.

Figure 8.2: GMP Benefits by Category

GMP Benefits by Category		
As of December 22, 2022	**Nominal ($M)**	**NPV ($M)**
Avoided Infrastructure Costs	**$ 1,093.9**	**$ 464.3**
Reduced DER Curtailment	**$ 848.7**	**$ 624.5**
VVO/CVR Benefits	**$ 755.8**	**$ 582.5**
Reduced Outage Frequency Benefits	**$ 527.7**	**$ 377.1**
Whole House TOU/CPP	**$ 366.7**	**$ 272.6**
EV/TVR Benefits	**$ 180.4**	**$ 130.9**
Utility O&M Savings	**$ 173.7**	**$ 72.9**
Total Calculated GMP Benefits	**$ 3,946.9**	**$ 2,524.7**

The benefits and costs are both estimated over a 20-year period. The bulk of the costs occur in the first five years of the program (2023-2028), while the benefits tend to occur later in the analysis period. Estimated annual costs and benefits are shown in Figure 8.3 for the GMP. Most costs occur throughout the program based on deployment schedules developed by the Company for each grid modernization solution. There are some benefits which occur earlier in the study period due to rapid deployment of FLISR/Advanced Reclosers, and VVO/Smart Capacitors and Regulators. Figure 8.3 shows annual nominal benefits and costs by year while Figure 8.4 shows cumulative nominal benefits and costs. Figure 8.4 can be used to determine the simple payback, or the length of time an investment reaches a break-even point based on nominal spend, which is estimated to be achieved in approximately eight years based on the quantified costs and benefits included in this GMP.

Figure 8.3: Annual Nominal BCA Results for the GMP Plan

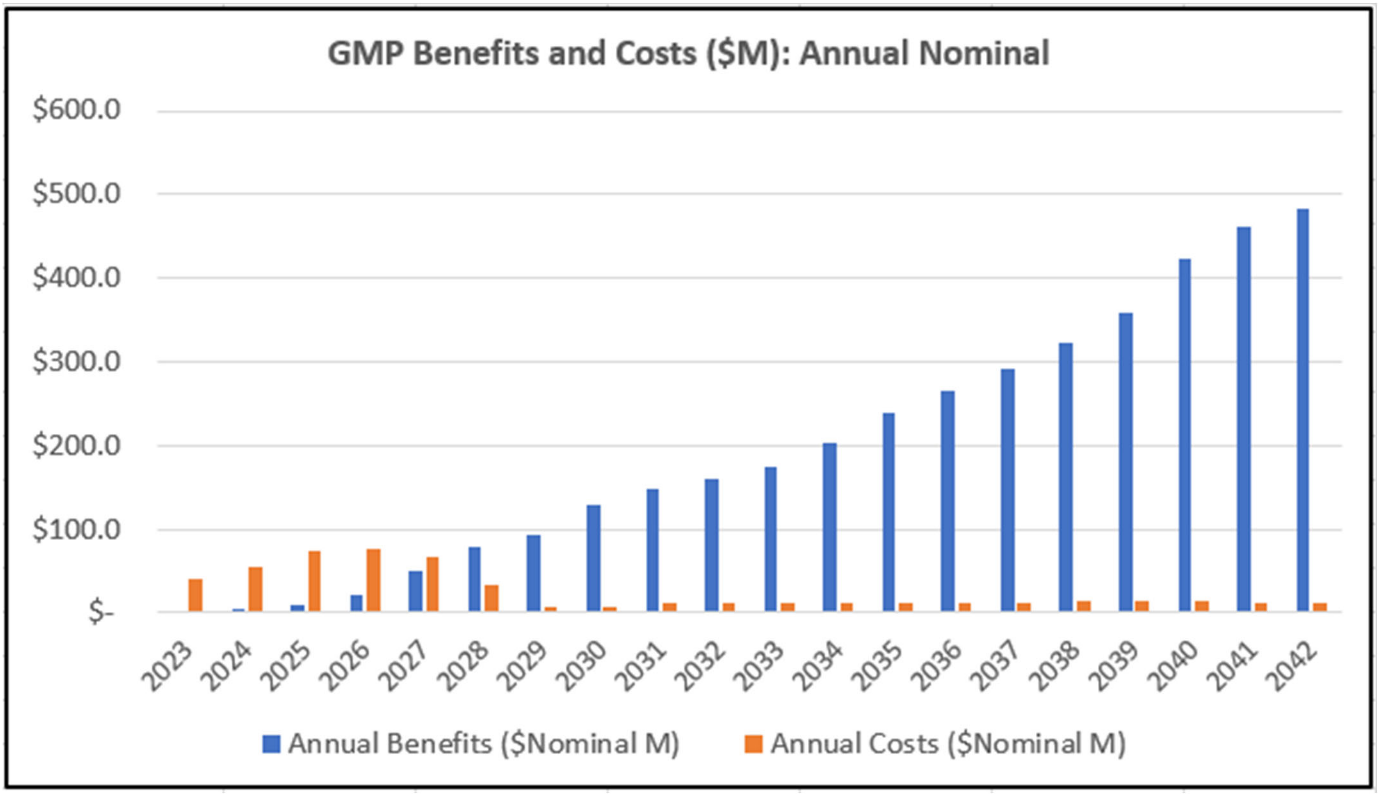
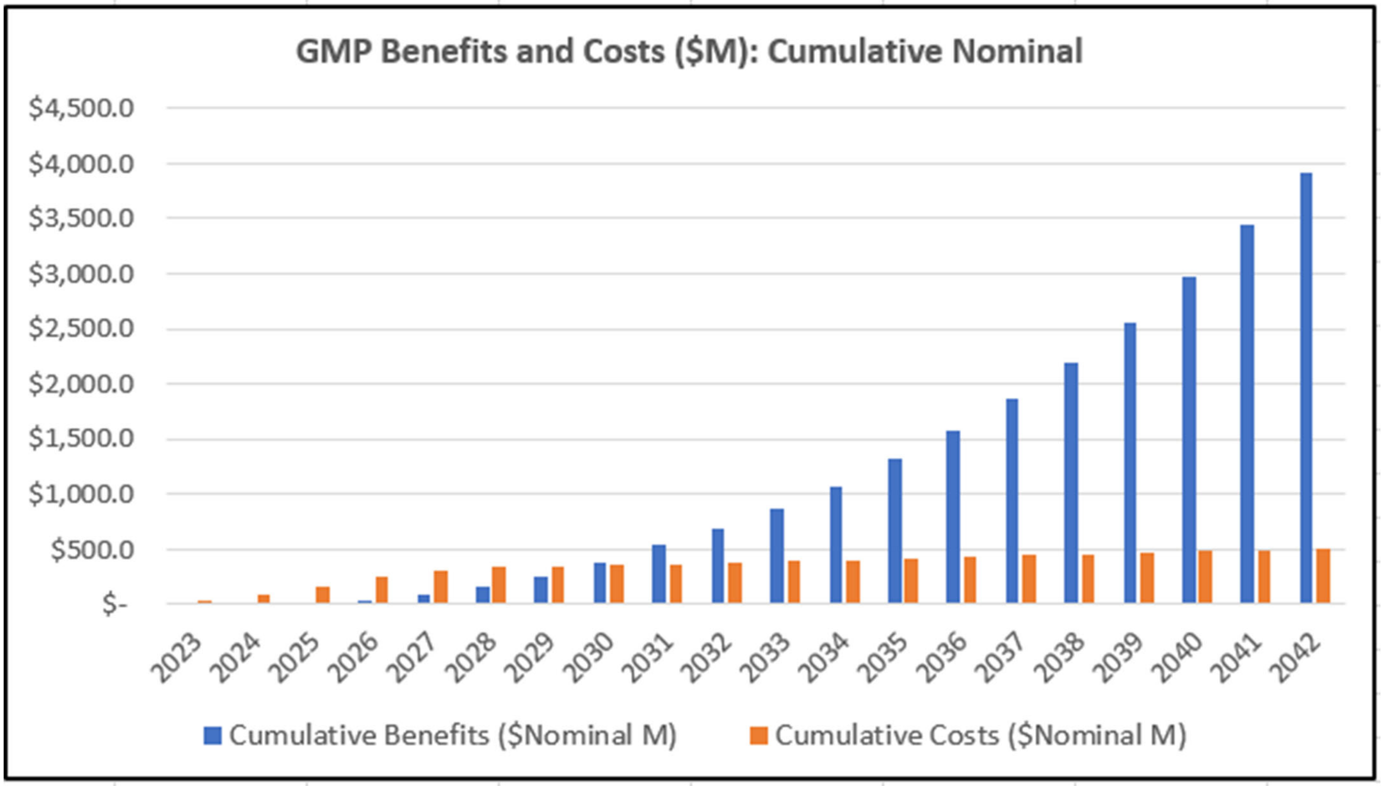


Figure 8.4: Cumulative Nominal BCA Results for the GMP Plan



Figures 8.5 and 8.6 show the same benefit and cost values from an NPV ($2023) perspective. When the cumulative, NPV ($2023) costs and benefits are considered, the payback period remains at approximately eight years, with the project breaking even in 2030.

Figure 8.5: Annual NPV ($2023) BCA Results for the GMP Plan

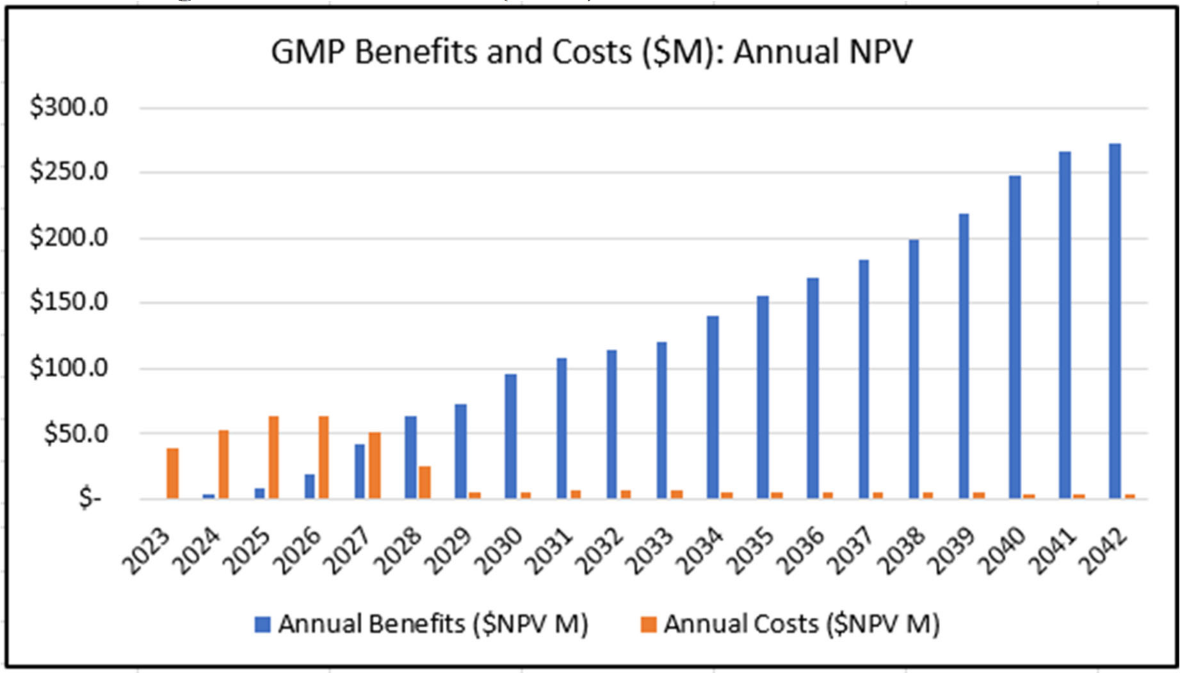
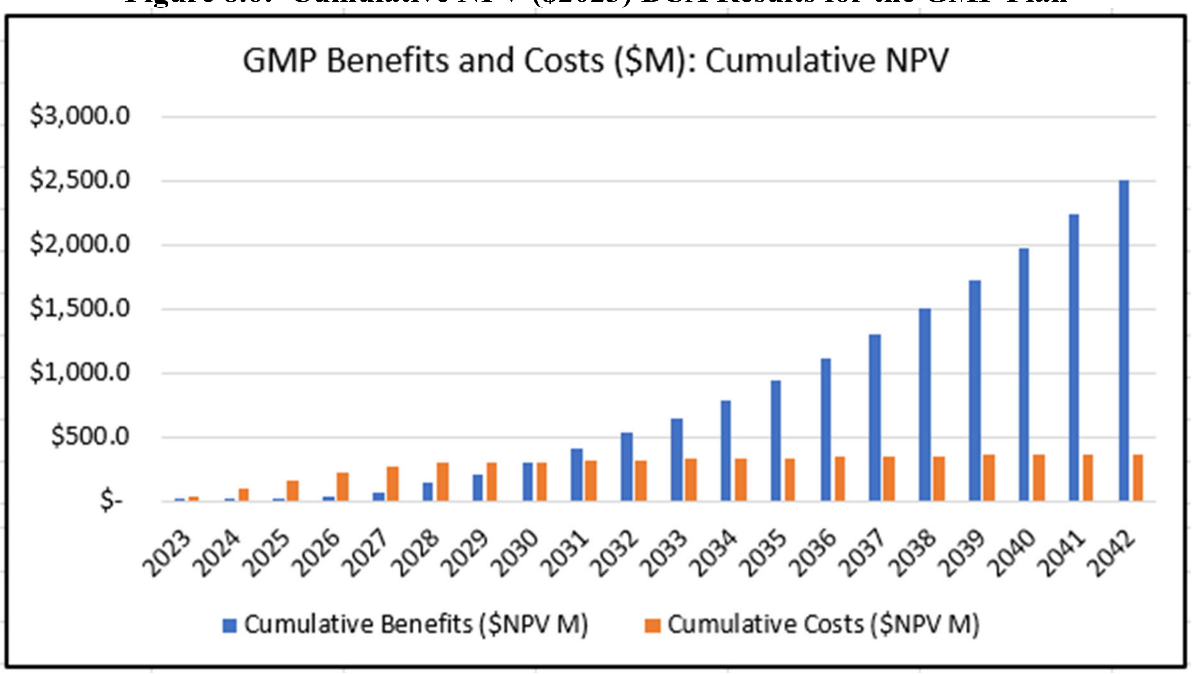


Figure 8.6: Cumulative NPV ($2023) BCA Results for the GMP Plan



8.2 System Analyses used in BCA Development

The Company used several different system and reliability analyses to estimate the benefits used in the BCA, as well as industry research, PPL Electric experience and information from Subject Matter Experts ("SMEs") from both Rhode Island Energy and PPL Electric.

The Distribution Study

As described in detail in Section 5 and Section 7, Rhode Island Energy conducted a leading-edge, 8760-hour long-range planning analysis for 2030, 2040, and 2050. The study analyzed the needs of the Company's system under a scenario designed to meet Rhode Island's Climate Mandates. The scenario included forecasts of DER penetration, EV growth and EHP growth. Two alternatives were studied. One alternative, the No Grid Modernization alternative was to build out the electric grid using only traditional solutions, including line rephasing, reconductoring or installing new feeders and new conductor routes, new substations; and field devices, like traditional capacitors, regulators, and reclosers with localized/un-automated controls. The second alternative, the Grid Modernization alternative, includes the Foundational Investments; Advanced Field Devices that include capacitors, regulators, reclosers, electromechanical relays, and the communications and IT software needed to automate the grid. Foundational Investments, create new capabilities and functionalities that enable the electric distribution system to respond automatically to many of the issues that arise from the anticipated growth of DER, EV and EHP adoptions. The Grid Modernization alternative case also includes the impacts of Whole House TOU/CPP energy and peak shifts, EV TVR energy and peak shifts, DER Monitor/Manage, and the use of BESS to adjust the forecasted "duck curve" load shape.

Figure 8.7 lays out the assumptions of the two alternatives. The analysis resulted in significant Avoided Infrastructure (T&D) Costs which are discussed in more detail below.

Figure 8.7: Future State Assumptions

Future State Assumptions	No Grid Modernization Alternative	Grid Modernization Alternative
DER Penetration	Same across both alternatives	
EV and EHP Projections	Same across both alternatives	
Grid Infrastructure Technology	Traditional Solutions	Grid Modernization Solutions w/Reduced Traditional Solutions
Metering Technology	AMF	AMF

Customer Load Management Programs	Existing Energy Efficiency, System-wide DR	Future Energy Efficiency& Feeder specific DR, NWA
DG Policies and Programs	Rigid Interconnection Standards Seasonal Curtailment and 100% Curtailment by DG site reclosers for large units	Flexible Interconnection Standards, Smart Inverters, Granular DG Curtailment, Voltage control and ramping provided for individual DG
Rate Policies and Programs	Limited TVR achievable due to AMF meters	Locational TVR and CPP implemented

DER Curtailment Analysis

As part of the Distribution Study, Rhode Island Energy analyzed the amount of DER curtailment that would be needed under each of the alternatives studied. With the traditional solutions identified in the No Grid Modernization Alternative, extreme amounts of curtailment are needed to operate the system. Using the Grid Modernization alternative, with the installation of Foundational Investments, a significant reduction in the amount of DER that would need to be curtailed was enabled by DER Monitor/Manage, TOU/CPP/TVR and BESS.

Reliability/Recloser Analysis

A reliability analysis was performed to understand the impact of installing reclosers and using them in conjunction with the ADMS-FLISR application that is being made available to Rhode Island customers through ADMS Basic. The reclosers are used to segment customers into groups of 500 customers (known as sectionalizing). Currently, when outages occur, because the Company’s system is not sufficiently sectionalized, many more customers experience outages than would occur if reclosers are installed to this standard. As described in the analysis in Section 6, reliability as measured by SAIFI, will improve by up to 30% compared to historic reliability performance. The results of this analysis were run through DOE’s ICE calculation tool to determine the benefit to customers of reducing the outages they experience.

Volt/Var Optimization Analysis

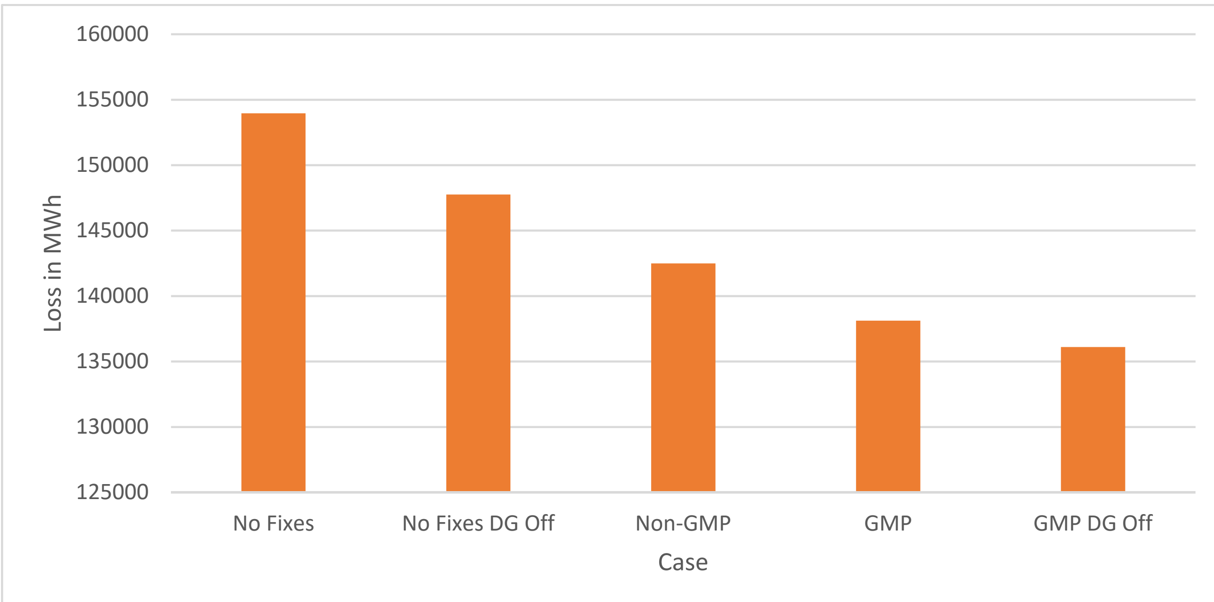
The volt/var optimization study presented in Attachment L provides an analysis performed by Rhode Island Energy to determine the potential impacts and the magnitude of the impacts that DG can have on VVO systems and also to explore how grid modernization concepts can be used to mitigate the DG impacts. This analysis illustrates the importance of grid modernization with the proliferation of DG on Rhode Island Energy distribution feeders. By enabling grid modernization functionality (i.e., DER Monitor/Manage), energy savings were maximized, even with a high penetration of DG. The analysis results indicate an energy savings in excess of 5% with grid modernization functionality as proposed in the GMP.

Rhode Island Energy has been performing a Volt/Var Optimization-Conservation Voltage Reduction pilot on several feeders in its service territory and also has conducted a significant body of research on VVO/CVR programs to develop estimates of energy and peak savings from VVO/CVR, and to determine how much could result from AMF meters and how much could result from grid modernization using Smart capacitors and Regulators, and Advanced Reclosers with ADMS - VVO. In this BCA, a conservative approach is being used to identify the GMP VVO benefits. The AMF BCA was credited with a 0.5% energy savings for VVO with the benefit of AMF meters, and the GMP BCA is credited with an additional 2% energy savings and 0.66% peak savings with the addition of Smart Capacitors and Regulators, Advanced Reclosers, and ADMS – VVO.

System Loss Analysis

Attachment K of this report describes the results of a transmission and distribution study to determine the total system loss differences with and without grid modernization solutions and with and without DG online for each case. The Central Rhode Island East area was used for the simulation to compare the cases. The results of the study were not used in the BCA, rather they are intended for illustrative purpose to help identify the numerous benefits of the GMP solutions. As shown in Attachment K, the grid modernization alternative provided lower system energy loss than the No Grid Modernization alternative. *See* Figure 8.8.

Figure 8.8 CRIE Area Total Loss Over Case



8.3 Benefits Discussion

8.3.1 Introduction

Benefits and costs were estimated over a 20-year period, both in nominal values and in NPV ($2023). To develop NPV ($2023) values, Rhode Island Energy used its post-tax Weighted Average Cost of Capital ("WACC") at 6.97% to calculate the Costs and the Utility Savings. Rhode Island Energy used a societal discount rate of 3% to calculate the NPV ($2023) of the Direct Customer Savings and the Societal Savings. For benefits that utilized avoided costs from the Synapse AESC 2021 report, the Company expressed those amounts in $2021 real dollars regardless of the year for which they are estimated. Using those values directly resulted in summing to the NPV (in $2021) rather than summing to nominal dollars. To determine the benefits in nominal dollars, the AESC 2021 values were increased by 2%/year.

Benefits were placed into three categories: Utility Savings, Direct Customer Savings and Societal Savings. Utility Savings include those savings that are more direct savings to the utility and, ultimately, to the Rhode Island Energy customers. Direct Customer Savings include savings that go to particular groups of customers, who, in this analysis, include customers who experience an outage. Societal

Savings include costs that are incurred by society as a whole by the use of electricity but are not included ("embedded") in the price of electricity that customers pay.

For the purposes of estimating utility, customer, and societal benefits that are aligned with each grid modernization alternative, the Company developed several benefit impact areas, which are quantified in the BCA. Each quantified benefit impact area has been aligned with a particular GMP goal in Figure 8.9.

Figure 8.9: Alignment Between Rhode Island GMP Objectives and Quantified Benefit Impacts

GMP Goal	Benefit Impact Area
1) Give customers more energy choices and information	Whole House TOU/CPP
	Reduced DER Curtailment
	Electric Vehicle TVR
2) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term	O&M Savings
	Reduced Customer Energy Use – VVO/CVR
	Reduced System Capacity Requirements – VVO/CVR
	Reduced Outage Frequency
3) Build a flexible grid to integrate more clean energy generation	Avoided D-System Infrastructure Cost
	Reduced DG Curtailment

Each benefit impact area has been defined and categorized based on the GMP benefit categories below.

8.3.2 Avoided Transmission and Distribution Infrastructure Costs

The distribution study (8760-hour analysis) identified all the infrastructure that would be needed under both the Grid Modernization alternative and the No Grid Modernization alternative. The costs of that infrastructure includes:

- New and reconductored distribution lines,
- New and refurbished distribution substations,
- New and refurbished transformers,
- New transmission lines and substations, and
- BESS.

These costs are not included directly in the costs for this GMP. Rather, the total cost of the infrastructure for the Grid Modernization alternative was subtracted from the total cost of the No Grid Modernization alternative. These Avoided Infrastructure Costs are included in the benefits. Because the Grid Modernization Alternative costs were subtracted from the Avoided Infrastructure Costs, those costs are included in the analysis as a negative benefit rather than as a direct cost. The savings are presented by Planning Area in Figure 8.10.

Figure 8.10: Avoided Grid Modernization Alternative Infrastructure Cost by Planning Area

Avoided GMP Infrastructure Costs				
As of December 21, 2022	Nominal ($M)		NPV ($M)	
Tiverton Area - Avoided Infrastructure Costs	$	54.8	$	23.2
Providence Area - Avoided Infrastructure Costs	$	120.7	$	51.2
SCW Area - Avoided Infrastructure Costs	$	37.8	$	16.1
NCRI Area - Avoided Infrastructure Costs	$	165.7	$	70.3
SCE Area - Avoided Infrastructure Costs	$	86.9	$	36.9
BVN Area - Avoided Infrastructure Costs	$	68.5	$	29.1
BVS Area - Avoided Infrastructure Costs	$	102.5	$	43.5
CRIE Area - Avoided Infrastructure Costs	$	94.2	$	40.0
CRIW - Avoided Infrastructure Costs	$	193.8	$	82.3
EB - Avoided Infrastructure Costs	$	33.8	$	14.4
Newport Area - Avoided Infrastructure Costs	$	135.1	$	57.3
Total Avoided Infrastructure Costs	**$**	**1,093.9**	**$**	**464.3**

The values above are the differential between the No Grid Modernization alternative and the Grid Modernization alternative; they represent the costs that will not need to be spent on infrastructure if the GMP is implemented.

8.3.3 Avoided Distributed Energy Resource (DER) Curtailment

Reduced DER Curtailment estimates the value of fewer DER applications being withdrawn due to high interconnection costs and fewer production restrictions on DER that are in service. These savings can be achieved through the ability of the distribution system operator to monitor and manage DER and optimize power output from renewable DER rather than relying on seasonal curtailment to avoid thermal or voltage constraints.

Figure 8.11 shows the benefits associated with reduced DER curtailment. The benefits shown are the value of the energy savings from being able to produce the kWh from DER rather than purchasing the energy in the ISO-NE market.

Figure 8.11: DER Curtailment Benefits

Reduced DER Curtailment		
As of December 22, 2022	**Nominal ($M)**	**NPV ($M)**
Reduced Curtailment: Energy Savings	**$ 848.7**	**$ 624.5**

Reduced DG Curtailment also creates significant societal cost savings. Reductions in non-embedded central power plant emissions of CO_2, SO_2, and NO_x result from the ability of the distribution system operator to manage DER andoptimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints. Rhode Island Energy calculated the benefits associated with reduced NOx, CO2 and Public Health improvements but did not include those benefits in the BCA.

8.3.4 Customer Savings – Reduced Outage Frequency Using Reclosers/FLISR

Reduced Outage Frequency (SAIFI): Reductions in customer outages due to the ability of ADMS-FLISR and associated Advanced Reclosers to control the distribution system automatically to isolate a fault and restore power (e.g., ADMS-FLISR) rather than waiting for field crews to locate and restore power. Figure 8.12 shows customer savings associated with reduced outages due to Advanced reclosers in the Foundational Investments and ADMS-FLISR. These benefits were calculated by using the "Value of Reliability Improvements" model in the DOE's ICE tool. The ICE tool allows the user to input the improvement in SAIFI, SAIDI or CAIDI, the number of customers affected, the state in which the improvement takes place (Rhode Island), and the lifetime of the improvement. Rhode Island Energy estimated the value associated with a 0.26 reduction in SAIFI (from 0.92 to 0.68) as discussed in Section 6 for all of its customers. The total dollar savings are shown in Figure 8.12 and are significant. The dollar values represent the savings to customers of not having an outage, e.g., lost production time for industrial customers. The savings are estimated by customer class – residential, Small and Medium C&I customers and Large C&I customers. The savings are very small for residential customers and very large for the Large C&I customers.

Figure 8.12: Reduced Outage Frequency Benefits

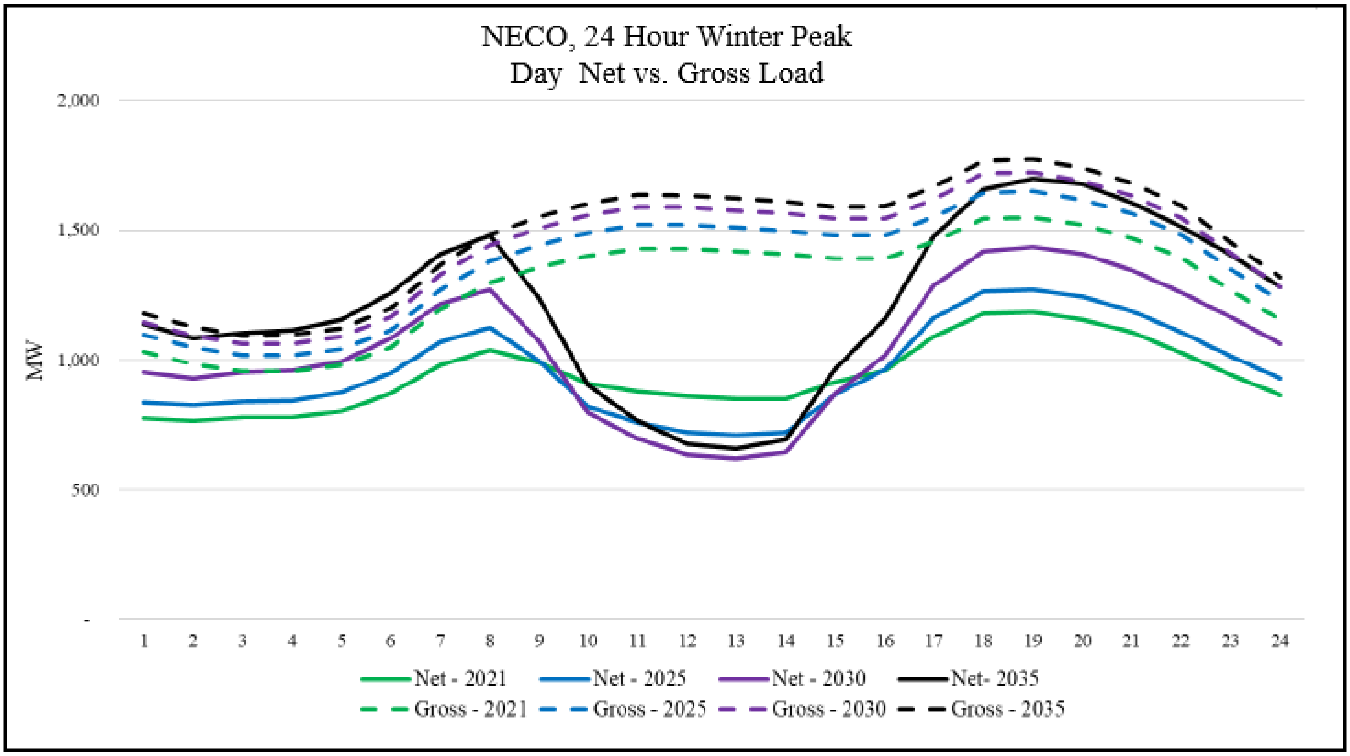
Reduced Outage Frequency Benefits due to FLISR		
As of December 21, 2022	Nominal ($M)	NPV ($M)
Reduced Outage Frequency Benefits	**$ 527.7**	**$ 377.1**

8.3.5 Whole House Time-of-Use/Critical Peak Pricing (TOU/CPP)

EV TVR and Whole House TOU/CPP are enabled by AMF. As the system becomes increasingly complex, the times that peaking conditions occur will change and markets will likely evolve and be created to provide new value propositions. With AMF, customers' demand and interval energy usage will be visible and presented in a way that customers can easily understand their load profile and make choices that reflect rate incentives in near-real time. AMF provides a platform that will enable the Company to overlay rate design parameters that vary by time, which could be by season, month, day, hour or every few minutes. Therefore, AMF does enable EV TVR and Whole House TOU/CPP. More information is provided in Section 13 of the AMF filing.

The load shapes experienced by the utilities are changing significantly and it is much more difficult to predict when the best time is to implement higher versus lower prices. Below is an example of how the load shapes are changing. Figure 8.13 shows the dual peaks associated with winter days as well as the very low load hours during the daytime hours due to solar and the rapid ramp ups needed as the sun sets. When the variable performance of wind is added, the load shape becomes even more unpredictable. When electricity use/production is changing so dynamically, TVR will be very helpful in managing the grid, but traditional AMR meters will not be of use for TVR that will need to be flexible–both in terms of the time when incentives are needed and the rates that will apply.

Figure 8.13: Projected Load Shapes with DER



The Whole House TOU/CPP rate construct used in the BCA consists of a two-period (on-peak, off-peak) TOU rate and a separate CPP rate. The TOU rate is based on, and captures variation in, ISO-NE energy market prices. The CPP rate includes all generation capacity costs, allocated over 70 hours per year. Based on the Company's expected duration of CPP events, this equates to approximately 12 to 15 events per year.

To calculate energy benefits from a Whole House perspective, Rhode Island Energy used a TOU construct to calculate energy savings associated with shifting electricity use from on-peak hours to off-peak hours. For Whole House peak savings, Rhode Island Energy assumed that only residential customers would participate and that participating customers would save 20% of their peak electricity usage on a Critical Peak Pricing rate. This approach results in system capacity savings, transmission and distribution savings, and Demand Reduction Induced Price Efficiency ("DRIPE") savings. Figure 8.14 shows the savings estimated from Whole House TOU/CPP rate constructs.

Figure 8.14: Whole House TOU/CPP Benefits

Whole House TOU/CPP - Mix of Opt-In and Opt-Out		
As of December 22, 2022	**Nominal ($M)**	**NPV ($M)**
GMP Total Trans Capacity Benefit: Whole House CPP	**$ 199.7**	**$ 148.5**
GMP - Total System Capacity Benefit: Whole House CPP	**$ 132.6**	**$ 98.6**
GMP Total Capacity DRIPE Benefit: Whole House CPP	**$ 11.93**	**$ 8.81**
GMP Total Dist Capacity Benefit: Whole House CPP	**$ 11.57**	**$ 8.60**
GMP - Total System Capacity Savings: Whole House TOU	**$ 10.84**	**$ 8.07**
Total Whole House TOU/CPP	**$ 366.7**	**$ 272.6**

EV TVR and Whole House TOU/CPP are included in both the AMF Business Case and in the GMP. The AMF Business Case included 20% opt-in for benefits. This limited participation was based upon only having wholesale markets to differentiate highs and lows in the rate design. With the addition of the GMP, the Company will have knowledge of localized distribution system violations that can be further included in highs and lows of rate designs. Bringing this added element to the value proposition will motivate greater participation. In the GMP BCA, the Company calculated a mix of the Opt-In program and the Opt-Out program. The Company assumed the Opt-In program would be in place from 2026-2030 and assumed the Opt-Out program would be in place starting in 2031. After calculating the value of the benefit with this mix, the Company subtracted out the benefits that were taken in the AMF Business Case to avoid double counting.

An Opt-Out approach will become both achievable and necessary over time. As customers become more familiar with TVR, the information and flexibility provided by AMF meters and energy management devices, they will also become aware of the savings potential. Furthermore, enabling technologies can be introduced to make participation easier and behavioral messaging can be performed to highlight savings opportunities that can be generated by participating in a TOU/CPP/TVR program. In addition, given the projected penetration of DER, EVs and EHPs, the Company will have an opportunity to increase the peak-to-off-peak price ratio to ramp up participation in these programs and load shifting behaviors to help the Company maintain reliability and reduce DER curtailment. The combination of customer familiarity and ease of participation and affordability will be key success factors for making the shift to a viable Opt-Out rate design with a high level of participation.[87] Several

[87] Moving Ahead with Time Varying Rates (TVR), US and Global Perspectives, Ahmad Faruqui, Ph.D., The Brattle Group, April 6, 2022, https://www.brattle.com/insights-events/publications/moveing-ahead-with-time-varying-rates-TVR-us-global-perspectives/

studies indicate that opt-out programs are much more successful in attaining and retaining customer participation than opt-in programs.[88]

8.3.6 Volt/Var Optimization/Conservation Voltage Reduction (VVO/CVR)

Distribution system operators in Rhode Island currently have very limited awareness of high or low voltage conditions across distribution feeders; reverse flow information; and distribution transformer loading issues. The Foundational Investments will provide the electric distribution system operators with critical real-time situational awareness of the electric networks including voltage deviations and the opportunity to optimize the voltage profile.

This data will include locational knowledge of energy usage, voltage, current and flow on the Rhode Island Energy feeders and some ability to adjust voltage levels. The Advanced Capacitors and Regulators coupled with ADMS-VVO will provide the opportunity for VVO, resulting in CVR. Rhode Island Energy estimates that VVO as a result of the Foundational Investments will result in 2.0% energy savings overall and 0.66% peak savings. This assumption has been confirmed as reasonable from analysis of Rhode Island Energy's VVO/CVR pilot that has been implemented at three substations. The pilot was evaluated by a third-party vendor and, for two of the three substations, the kWh savings on each feeder ranged from 1.3%-3.5% on each feeder. The weighted average savings for one of the substations was 1.5% and the weighted average savings for the other substation was 3.5%.

VVO/CVR results in many different benefits, including energy and capacity cost savings, and societal savings. The benefits begin in 2026 at 20% and increase by 20% per year until they reach 100% in 2030. Figure 8.15 shows the benefits resulting from a 2.0% reduction in energy use and 0.66% reduction in peak.

[88] *Id*.

Figure 8.15: Benefits from GMP VVO / CVR

GMP VVO/CVR Benefit		
As of December 22, 2022	Nominal ($M)	NPV ($M)
GMP - Total Non-Embedded CO2 Benefit: VVO/CVR	$ 486.7	$ 376.2
Energy Savings: VVO/CVR	$ 154.3	$ 119.1
Monetized CO2 Benefit: VVO/CVR	$ 71.2	$ 54.5
GMP - Trans Capacity Benefit: VVO/CVR	$ 22.1	$ 17.1
GMP - System Capacity Benefit: VVO/CVR	$ 14.1	$ 10.6
GMP - Total Public Health Benefit: VVO/CVR	$ 2.3	$ 1.8
Reduced VVO Lease Costs	$ 2.2	$ 1.1
GMP - Total Non-Embedded NOX Benefit: VVO/CVR	$ 1.4	$ 1.1
GMP - Dist Capacity Benefit: VVO/CVR	$ 1.4	$ 1.1
Total VVO/CVR Benefits	**$ 755.8**	**$ 582.5**

8.3.7 EV TVR Benefits

AMF provides the ability to implement TVR in the future; GMP provides the knowledge of distribution load shapes and the impacts to the distribution system as the load shape changes from contributions of increased EV penetration. TVR can be used to encourage EV charging during off peak conditions thereby shifting load to avoid system constraints and violations. This section briefly describes the major assumptions Rhode Island Energy used for estimating benefits from EV TVR and presents the resulting savings. Much more detail on TVR and the Company's assumptions was presented in Section 13 of the Company's AMF filing.

The major assumptions included in estimating the benefits of EV TVR include:

- EVs are increasing in number from approximately 7,000 vehicles in 2022 to 790,000 vehicles in 2042
- EVs use between 3,500 kWh/year and 4,300 kWh/year
- EV owners moving between 13% and 27% of their total kWh charged from peak hours to off-peak hours
- EVs contribution to system peak being between 0.6 kW and 1.4 kW, depending on the year
- EV owners shifting between 29% and 60% of their peak hour usage off-peak.

It is important to note that Rhode Island Energy is assuming a significant amount of diversity in peak hour charging, i.e., not all EVs are plugged in at the same time. EVs that are plugged in draw either 1.4 kW or 7.2 kW, depending on the type of charger they have. Today, if all EVs are plugged in simultaneously, the EV load on the system would be 33.6 MWs, compared to a peak load of 1,800 MWs. In 2042, due to the number of EVs on the system, if all EVs were plugged in simultaneously, the EV load on the system would be 3,800 MWs, compared to a forecast system peak load of 3,652 MWs.

Figure 8.16 shows the benefits from Grid Modernization related to EV TVR.

Figure 8.16: Benefits from Electric Vehicle Time Varying Rates

EV/TVR Benefit - Mix of Opt-In and Opt-Out		
As of December 22, 2022	Nominal ($M)	NPV ($M)
GMP - Total System Capacity Benefit: EV TVR	$ 172.8	$ 125.3
GMP - Total Energy Shift Benefits: EV TVR	$ 7.6	$ 5.6
Total EV/TVR Benefits	**$ 180.4**	**$ 130.9**

8.3.8 Avoided O&M Costs

Grid modernization investments will provide the ability to better and more efficiently manage the distribution system. For example, this will result in fewer truck rolls, less field work and less operations analysis work to identify outage locations and the best way to restore customers. Rhode Island Energy estimated these savings by using PPL Electric's experience and the benefits achieved from more efficient operations over the last 10 years after deploying grid modernization investments. PPL Electric has managed their operations over this period with O&M expenditures increasing at 0.5%/year compared to an average distribution utility which increases O&M expenditures by approximately 2.0%/year. Using the typical annual increase for distribution O&M expenditure for U.S. utilities, avoided O&M savings were calculated based on a 2% increase per year versus a 0.5% increase per year. Analysis of Rhode Island Energy's distribution O&M costs for the last 10 years indicates that the Company's annual increase has been 3.0% per year, significantly higher than the average utility and even more so compared to PPL Electric. The results are shown in Table 8.17 below.

Figure 8.17: Avoided O&M Costs

Utility O&M Savings		
As of December 22, 2022	**Nominal ($M)**	**NPV ($M)**
Utility O&M Savings	**$ 171.5**	**$ 71.8**
Communication Savings due to SS Fiber	**$ 2.2**	**$ 1.1**
Total O&M Savings	**$ 173.7**	**$ 72.9**

8.3.9 Societal Benefits

There are a number of societal benefits that will result from grid modernization investments, including DER Monitor/Manage and these are discussed above with the programs that produce those savings.

8.3.10 Non-Quantified Benefits

In addition to the quantified benefits presented in this BCA, per Docket No. 4600 Guidance, the Company is providing additional non-quantified benefits that should be recognized qualitatively. These benefits are not quantified at this time due to lack of data or lack of an accepted method.

These benefits, however represent important additional grid modernization value. If considered as part of the BCA, these benefits can be considered as directionally increasing the benefit-costs ratio and potentially making the grid modernization programs even more valuable and cost-effective. These benefits will continue to be evaluated and could be quantified in future BCA results as additional data and methods are developed.

Below is a description of the benefits that were not quantified.

Reduced Losses: As described above, Rhode Island Energy performed a grid modernization loss study to compare the differential in system losses between the No Grid Modernization alternative and the Grid Modernization alternative. The study showed system loss reductions as a result of grid modernization, but those loss reductions were not included in the calculated benefits.

Local Economic Impacts: The impact of the significant GMP investments on the Rhode Island economy was not quantified in the BCA. Investments of this magnitude have ripple effects on the local economy, resulting in a multiplier impact of the investments. These ripple effects include suppliers of equipment and material, local contractors and other local businesses who may experience an increase in revenue due to the work being done across the Rhode Island Energy service territory. These benefits were not calculated as part of this BCA.

Improved Long-Term Forecasting for Planning due to Granular Data: Rhode Island Energy has made tremendous progress with its leading-edge 8,760-hour analysis of projected loads. However, granular data and improved situational awareness from AMF, Advanced Field Devices, and ADMS provides a step change in available data for grid planning and operations. This data can be used to more accurately design and plan for future distribution system needs through better forecasting of where and when DER will be located, used, and how the distribution system will perform over time. AMF also provides more timely, granular values that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder. This complete data set can be modeled directly, and more detailed load and DER forecasts can be developed for planning needs.

More Equitable Cost Allocation due to Granular Data: Grid modernization will enable improvements in the ability to allocate costs to different classes of customers in a way that more precisely reflects their respective contributions to system-level costs, and will support development of more cost-reflective rates and pricing that limits cross-subsidization. Future pricing and allocation mechanisms like TVR, AMF and other grid modernization investments will enable the Company to more accurately reflect the costs of producing and delivering electricity, which will promote economic efficiency and lead to a lower-cost system. In addition, when the prices consumers pay are more closely aligned with thecosts they represent, a more fair and equitable allocation of electricity sector costs results. AMF and other grid modernization investments are needed to provide granular (both in time and space) grid-level data.

Improved Short-Term Forecasting for Operations due to Granular Data: Better forecasting and monitoring of load, generation, and grid performance enabled by AMF, ADMS (i.e., ADMS-based load forecasting application), Advanced Field Devices, and DERMS can enable distribution system operators to actively manage grid demand and grid supply maximizing asset utilization and allowdispatch of a more efficient mix of generation and ancillary services (e.g., spinning reserve, frequency regulation) and reduce transmission congestion to reduce generation and transmission costs, and ultimately, reduce electricity procurement costs on behalf of customers. Improved forecasting and monitoring of load and generation may also allow for less restricted DER operation in areas susceptible to system voltage or thermal constraints and allow NWA assets to be utilized for other beneficial uses if the electric distribution system operator can forecast that it does not needthe NWA for reliability needs during a certain time period.

Improved Storm Recovery due to Granular Data and Distributed Automation: While a reliability benefit was quantified for outages, based on SAIDI and SAIFI reductions from Advanced Reclosers & Breakers and FLISR, the quantified benefit does not include outages dueto major storm events; however, granular data and improved situational awareness due to the expansion of both monitoring and control from Advanced Field Devices, supported by ADMS and other grid modernization investments, allows for quicker fault location confirmation and theability for the distribution system operators to remotely sectionalize faulted areas, reconfigure, and restore customers outside fault areas before field crews arrive on site during storm-related outages. Automation of these remote-control capable devices via a centralized program like FLISR will allow for the identification of a faulted area and the automated restoration of customers can provide additional reliability benefits, which have not been quantified to date.

8.4 Cost Estimation

8.4.1 Approach

Rhode Island Energy worked with vendors, SMEs from both Rhode Island Energy and PPL Electric, used industry research, and independent expertise to develop estimated costs for this GMP. The costs include those developed through the FY2024 Electric ISR Plan proceeding (installation project costs for new distribution investments), RTB costs including O&M to maintain the devices and telecommunications costs, and costs to implement DER Monitor/Manage. As described in Section 6, the GMP investments are categorized as Operational Systems and Applications, Advanced Field Devices and Communications (Fiber). The costs were developed for a 20-year analysis period. Values are presented below in Figure 8.18 on both a nominal basis and a NPV ($2023) basis.

Figure 8.18: 20 Year GMP Nominal and $2023 NPV Totals

Program Category	Project Costs (000's)				Future Project	Operating Costs		Total All BCA	Total All BCA
	Install	Remove	OPEX	Total	Costs	RTB OPEX	RTB Telecom	Costs (Nominal)	Costs (NPV)
Communications (Fiber)	$ 91.1	$ 0.9	$ 0.9	$ 93.0	$ -	$ 12.3	$ -	**$ 105.3**	**$ 86.2**
Advanced Field Devices	$ 191.4	$ 10.2	$ 5.3	$ 206.9	$ -	$ 26.1	$ 8.6	**$ 241.7**	**$ 194.1**
Operational Systems & Applications	$ 39.4	$ 0.3	$ 0.3	$ 40.0	$ 103.3	$ 38.7	$ -	**$ 182.0**	**$ 93.5**
Total All GMP	**$ 321.9**	**$ 11.4**	**$ 6.6**	**$ 339.9**	**$ 103.3**	**$ 77.1**	**$ 8.6**	**$ 529.0**	**$ 373.8**

8.4.2 Summary of Costs

The Company developed cost estimates for the Foundational Investments included in the ISR plan, plus telecom costs for the advance field devices and RTB O&M costs for all categories in the GMP. For the Foundational Investments included in the ISR plan, the distribution investment costs were split between CAPEX and OPEX. Only the installation component of the CAPEX costs was included in the ISR plan. The removal component of the CAPEX costs and the OPEX component of the Foundational Investments are included in the GMP costs totals, but not included in the ISR cost totals. The ISR plan includes only those costs related to distribution assets. The costs related to the Communications (Transmission Fiber) project are not included in the ISR but are included in the GMP cost totals. The FY2024 Electric ISR Plan filed with the PUC includes a 21-month period from April 1, 2023 through December 31, 2024. – shown below as CY23 (9 months 4/23 – 12/23) and CY24 (12 months 1/24 – 12/24) totaling $81.9M. The periods CY25, CY26 and CY27, total $187.6M. And the GMP project costs include an additional year with CY28, totaling $30.1M. See figure 8.19 for the details.

Figure 8.19: Foundational Investment Install Totals in ISR Plan CY23 – CY28

Program Category	CY23 (9 months)	CY24 (12 months)	CY25	CY26	CY27	CY28	Total
Communications (Distribution Fiber) Install	$ 8.1	$ 11.3	$17.9	$15.3	$ 8.0	$ 8.0	**$ 68.6**
Advanced Field Devices	$ 24.1	$ 34.4	$37.0	$41.2	$40.1	$14.7	**$ 191.4**
Operational Systems & Applications	$ 1.7	$ 2.3	$ 6.3	$ 8.3	$13.5	$ 7.4	**$ 39.4**
Total ISR Submitted	**$ 33.9**	**$ 47.9**	**$61.2**	**$64.8**	**$61.6**	**$30.1**	**$ 299.5**
Project Costs Removal	$ 0.9	$ 1.3	$ 1.6	$ 2.6	$ 2.8	$ 1.9	**$ 11.1**
Project Costs OPEX	$ 1.5	$ 1.7	$ 1.7	$ 0.6	$ 0.6	$ 0.2	**$ 6.3**
Communications (Transmission Fiber) Project Costs	$ 3.3	$ 4.3	$ 7.7	$ 7.7	$ -	$ -	**$ 23.0**
Total Foundational Investments	**$ 39.6**	**$ 55.2**	**$72.2**	**$75.7**	**$65.0**	**$32.2**	**$ 339.9**

Figure 8.20 below depicts the GMP costs developed for the GMP. The costs are grouped into three categories following the layout of the GMP in Section 6: 1) Communications (Fiber) 2) Advanced Field Devices 3) Operational Systems and Applications. The total costs are $529 million Nominal and $373.8 million NPV ($2023). The Net Present Value is roughly 2/3 of the Nominal costs because the bulk of the spend in the GMP is from years 2023-2028.

Figure 8.20: Total GMP BCA Costs by Category

Program Category	Total All BCA Costs (Nominal)	Total All BCA Costs (NPV)
Communications (Fiber)	$ 105.3	$ 86.2
Advanced Field Devices	$ 241.7	$ 194.1
Operational Systems & Applications	$ 182.0	$ 93.5
Total All GMP	**$ 529.0**	**$ 373.8**

8.4.3 Operational Systems and Applications

Operational Systems and Applications costs include IT Infrastructure, ADMS software, Mobile Dispatch and DER Monitor/Manage. Figure 8.21 shows the total $182 million Nominal and $93.5 million NPV ($2023) for Operational Systems and Applications, this category makes up 34% of the total costs of the GMP program.

Figure 8.21: Operational Systems and Applications

Program Category	Project Costs (000's)				Future Project Costs	Operating Costs		Total All BCA Costs (Nominal)	Total All BCA Costs (NPV)
	Install	Remove	OPEX	Total		RTB OPEX	RTB Telecom		
Total ADMS	$ 11.5	$ 0.1	$ 0.1	$ 11.7	$ -	$ 7.7	$ -	$ 19.4	$ 12.9
Total IT Infrastructure	$ 16.4	$ 0.2	$ 0.2	$ 16.7	$ -	$ 16.9	$ -	$ 33.6	$ 22.1
Total Mobile Dispatch	$ 0.8	$ 0.0	$ 0.0	$ 0.8	$ -	$ 0.1	$ -	$ 0.9	$ 0.7
Total DER Monitor Manage	$ 10.7	$ -	$ -	$ 10.7	$ 103.3	$ 14.0	$ -	$ 128.0	$ 57.8
Total Operational Systems & Applications	**$ 39.4**	**$ 0.3**	**$ 0.3**	**$ 40.0**	**$ 103.3**	**$ 38.7**	**$ -**	**$ 182.0**	**$ 93.5**

ADMS:

The ADMS system makes up approximately 11% of the total Operational Systems and Applications cost. The proposed ADMS investment is an integrated grouping of hardware and software necessary for Distribution Control Center operations to provide greater visibility, situation awareness, and optimization of the electric distribution grid as well as improved efficiencies through automating multiple control center processes. ADMS is a critical platform to provide visibility and provide the capability to manage the grid as it becomes more complex and for the integration and operational management of DER as their impact on grid performance grows. ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices, DER, and AMF data as it becomes available. For example, when planning to reconfigure the grid, ADMS will allow the operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach to understand operational ramifications. ADMS is responsible for a series of phased in applications that provide incremental benefits that are described in Section 6. One example is for DER to become operationally integrated into the ADMS network model using ADMS - DERMS in conjunction with DER Monitor/Manage to allow operators to assess the effect of DER on the grid, as well as leverage them for grid support where possible.

IT Infrastructure:

The IT Infrastructure costs are approximately 18% of the Operational Systems and Applications costs. The proposed underlying IT infrastructure investments in data management and enterprise integration, and corporate PI historian are necessary to achieve full benefits. Cyber security is a necessary capability to operate a safe, reliable and cost-effective electric distribution system. GMP includes investments that will build foundational data management capabilities by enabling enhanced data integrations between the various GMP applications such as ADMS, VVO/CVR, corporate PI Historian and GIS. This plan also includes a cyber services component.

Mobile Dispatch:

The GMP proposes investments in mobile dispatch system and associated devices. Mobile Dispatch is expected to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety.

DER Monitor/Manage:

As more DER are interconnected with the Company's distribution system, Rhode Island Energy will have to balance demand and generation simultaneously and will increasingly experience issues on its electric distribution system without any way to monitor and manage those resources. Solar and other intermittent resources can negatively affect the voltage on the electric distribution system, resulting in delayed interconnection or distribution system reinforcements before additional DER can be installed. Given Rhode Island Energy's current inability to directly communicate with and manage DER to mitigate resulting power quality issues and to leverage grid support functionality, the amount of intermittent generation that can be interconnected must be limited to maintain system stability and reliability. Moreover, in the absence of such ability, the reliability, safety, and efficiency of Rhode Island Energy's service will be placed at increased risk with each new DER that is interconnected with the distribution system. As more DER connect to the system, the devices need to be integrated with utility operations at all levels for management and monitoring purposes. DER Monitor/Manage is the only program category included in the GMP that includes future project/investment costs. As incremental DER are interconnected with the Rhode Island Energy system through the 20-year BCA period, costs for each DER to participate as DER Monitor/Manage to be fully integrated with the system were added into the BCA. See Attachment G for additional information on DER Monitor/Manage.

8.4.4 Advanced Field Devices

This cost category includes the Advanced Field Devices that will be deployed in the field to provide the visibility, sensing and automation needed to monitor and manage Rhode Island Energy's grid. The total costs of the Advanced Field Devices are $241.7 million Nominal and $194.1 million NPV ($2023), representing approximately 46% of the total cost of the GMP program. The Advanced Field Devices include Reclosers, Electromechanical relays, Capacitor Banks (smart) and Regulators that have been included in the FY 2024 Electric ISR Plan. Figure 8.22 shows the costs for each of these components and each one is discussed further below.

Figure 8.22: Costs of Advanced Field Devices

Program Category	Project Costs (000's)				Operating Costs		Total All BCA Costs	Total All BCA Costs (NPV)
	Install	Remove	OPEX	Total	RTB OPEX	RTB Telecom		
Total Recloser Cash Flow	$ 128.9	$ 1.3	$ 1.3	$ 131.6	$ 14.1	$ 5.2	$ 150.9	$ 122.7
Total Cap Bank and Regs Cash Flow	$ 30.5	$ 2.7	$ 0.7	$ 33.9	$ 8.1	$ 3.0	$ 45.0	$ 34.9
Total Electromechanical Relay Cash Flow	$ 32.0	$ 6.1	$ 3.3	$ 41.4	$ 3.9	$ 0.5	$ 45.8	$ 36.5
Total Advanced Field Devices	**$ 191.4**	**$ 10.2**	**$ 5.3**	**$ 206.9**	**$ 26.1**	**$ 8.6**	**$ 241.7**	**$ 194.1**

Advanced Reclosers

Advanced Recloser deployment is being proposed to improve reliability in the near-term, add capability to remotely reconfigure the system, and to increase operational visibility. The reclosers will be used to sectionalize customers into groups of 500 customers, which will greatly reduce the number of customers impacted by outages and improve Rhode Island Energy's SAIFI performance accordingly. The proposed reclosers are a significant portion of the costs of the Advanced Field Devices, at approximately 62%.

Electromechanical Relay Upgrades

The GMP proposes investment to upgrade electromechanical relays to digital relays. Digital relays adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups. Additionally, the fault location information provided by digital relays minimizes outage duration because it helps reduce the time field technicians spend searching for issues. Improving how the power system is monitored and controlled can provide operations and maintenance benefits that exceed the initial capital investment.

Advanced Capacitor Banks and Regulators

Rhode Island Energy is already experiencing voltage excursions, particularly where there is a significant penetration of DER. As DER penetration increases, maintaining voltage within limits will become even more challenging. The proposed Advanced Capacitors & Regulators would adjust system voltages up or down in a dynamic manner to accommodate the variable output of these DER technologies while providing service reliably in compliance with voltage threshold requirements. In addition, the voltage control and near real-time measurements enable engineering and operations personnel to better manage voltage along individual feeders, ultimately resulting in lower costs to all Rhode Island Energy customers through optimization (e.g., VVO/CVR).

8.4.5 Communications (Fiber)

The GMP proposes to replace leased line services connecting substations with fiber optic cabling to improve data flow, resiliency, security, and reliability of backhaul communications, which Rhode Island Energy would own, operate and maintain as a private fiber network. Fiber costs are broken into Distribution Fiber and Transmission Fiber.[89] Figure 8.23 below reflects the total cost for the fiber at $105.3 million Nominal and $86.2 million NPV ($2023).

Figure 8.23: Fiber GMP Total

Program Category	Project Costs (000's)				Operating Costs		Total All BCA	Total All BCA
	Install	Remove	OPEX	Total	RTB OPEX	RTB Telecom	Costs	Costs (NPV)
Total Distribution Fiber	$ 68.6	$ 0.7	$ 0.7	$ 70.0	$ 9.3	$ -	$ 79.3	$ 64.3
Transmission Fiber	$ 22.5	$ 0.2	$ 0.2	$ 23.0	$ 3.0	$ -	$ 26.0	$ 21.9
Total Communications (Fiber)	**$ 91.1**	**$ 0.9**	**$ 0.9**	**$ 93.0**	**$ 12.3**	**$ -**	**$ 105.3**	**$ 86.2**

8.4.6 RTB Costs

As shown in Figure 8.24, RTB costs consist of both RTB - OPEX and RTB - Telecom. RTB – OPEX includes charges for operating and maintenance expense each year. RTB OPEX was calculated for all the Program Categories in the GMP. RTB – Telecom captures the monthly cellular costs for the advanced field devices. This category is the smallest of the four categories of costs, at $85.7 million Nominal.

[89] The fiber is a shared asset between Distribution and Transmission where only the Distribution Fiber has been included in the Foundational Investments submitted to through the FY24 ISR.

Figure 8.24: RTB Costs

Program Category	Operating Costs		Total All BCA Costs	Total All BCA Costs (NPV)
	RTB OPEX	RTB Telecom		
Communications (Fiber)	$ 12.3	$ -	**$ 12.3**	**$ 6.0**
Advanced Field Devices	$ 26.1	$ 8.6	**$ 34.7**	**$ 17.5**
Operational Systems & Applications	$ 38.7	$ -	**$ 38.7**	**$ 17.3**
Total All GMP	**$ 77.1**	**$ 8.6**	**$ 85.7**	**$ 40.8**

RTB – OPEX

RTB OPEX was calculated differently depending on the Program Category.

For the Advanced Field Devices, an annual O&M cost per device was used and escalated by 2.5% (labor escalation percentage) to determine the O&M total costs for the field devices. The price per device was provided by Rhode Island Energy personnel and is applied to all the devices in the Advanced Field Device category. The costs are set to begin based on the in-service schedule for each device.

For the Operational Systems and Applications and Communication (Fiber) categories, the Company used input from PPL Electric subject matter experts who provided a ratio of annual operating expense to total investment. This percentage was applied to the GMP investment costs to determine an annual RTB – OPEX value.

RTB – Telecom

RTB – Telecom cover monthly cellular costs. These costs were calculated using the in-service schedule for all Advanced Field Devices and applying a monthly service cost per device. The monthly service cost is based on the pooled rate that PPL Electric is currently paying for thousands of advanced field devices across its grid in Pennsylvania.

8.5 Sensitivity Analysis

This GMP leverages findings, results, and lessons learned from prior PPL deployments and from those of other utilities as well as advice and information from consultants and vendors. Any analysis would be incomplete without evaluating uncertainty. Rhode Island Energy evaluated two types of sensitivities – Basic Sensitivities and Issue-Specific Sensitivities. The Basic Sensitivities involve varying costs and benefits by some percentage to reflect the uncertainty that particular levels of costs or benefits will be achieved. Figure 8.25 lists and describes the different parameters (comprised of both cost and benefit factors) selected for the purposes of the Basic Sensitivity analyses performed by Rhode Island Energy. The analysis addresses each variable separately, and so with each sensitivity, only a single parameter is changed. Conducting the analysis in this manner helps identify the isolated impact on the GMP because of a change in a single variable.

Figure 8.25: Summary of Sensitivities and Rationale

Variable	Sensitivity Analysis	Description and Rationale
Foundational Field Devices and Run the Business (O&M) costs	10% Reduction (favorable) 10% Increase (unfavorable)	Many of the costs included in the BCA have been used by other utilities and by Rhode Island Energy; these costs are more certain. Other costs have less certainty, particularly in the long run. Rather than varying specific aspects of the cost, Rhode Island Energy calculated a +/-10% sensitivity on Foundational Field Devices and Run the Business costs.
Communications and IT costs and DER Monitor/Manage costs	25% Decrease (favorable) 25% Increase (unfavorable)	Communications and IT costs have traditionally been more uncertain than other types of costs. DER Monitor/Manage is a leading-edge technology with uncertain costs. To address these uncertainties, the Company has developed a +/-25% sensitivity for these two categories.
Benefits: Avoided Infrastructure Costs Reduced DER Curtailment Reduced Outage Frequency Whole House TOU/CPP VVO/CVR Benefits EV/TVR Benefits Utility O&M Savings	20% Decrease (unfavorable) 20% Increase (favorable)	Rhode Island Energy has grouped the benefits from the GMP program into seven categories. Each of these categories is uncertain, particularly in the long run. To address this uncertainty, the Company has estimated a +/-20% sensitivity for each of the seven categories.

8.5.1 Cost Sensitivities

The cost sensitivities involve varying each of the four categories of costs. Rhode Island Energy varied the Communication and IT costs and the DER Monitor/Manage costs by +/-25% because they are more uncertain than the Field Devices and RTB costs. The Company has extensive experience with purchasing and installing field devices and maintaining them; those two categories were varied by +/-10%. Figure 8.26 shows the results of these sensitivities as well as the results if all the costs turned out to be higher or lower than projected. As provided in the chart, the benefit-cost ratios for the individual favorable sensitivities range from 6.8 to 7.4, and when the sensitivities are combined, the benefit-cost ratio is 8.2. These values are compared to a Base Case benefit-cost ratio of 6.8 from an NPV perspective. The benefit-cost ratios for the individual unfavorable sensitivities range from 6.2 to 6.7, and when those sensitivities are combined, the benefit-cost ratio is 5.8. Even given all the costs being higher than forecast, the benefit-cost ratio remains very strong.

Figure 8.26: Cost Sensitivities

Costs Sensitivities								
As of December 21, 2022								
Costs Sensitivities	Base NPV ($M)		NPV ($M)		B/C Ratio	NPV ($M)		B/C Ratio
			Favorable: -25%/-10%			Unfavorable: +25%/10%		
Foundational Field Devices	$	176.5	$	158.8	7.1	$	194.1	6.5
Communications & IT	$	121.2	$	90.9	7.4	$	151.5	6.2
Run the Business (O&M)	$	18.3	$	16.5	6.8	$	20.2	6.7
DER Monitor/Manage	$	57.8	$	43.4	7.0	$	72.3	6.5
Total Sensitivity - Costs	$	373.8	$	309.5	8.2	$	438.0	5.8

8.6.2 Benefits Sensitivities

Similar to the Cost Sensitivities, Rhode Island Energy has varied all of the seven benefit categories. For the benefits, they have all been varied by +/-20%. Figure 8.27 shows the results of both the individual sensitivities and combining all the Benefit Sensitivities. As demonstrated in the chart, the benefit-cost ratios for the individual favorable sensitivities range from 6.8 to 7.1, and when the sensitivities are combined, the result is a benefit-cost ratio of 8.1. These values are compared to a Base Case benefit-cost ratio of 6.8 from an NPV ($2023) perspective. The benefit-cost ratios for the individual unfavorable sensitivities range from 6.4 to 6.7, and when the sensitivities are combined, the benefit-cost ratio is 5.4. Even given lower benefits than forecast, the benefit-cost ratio remains very strong.

Figure 8.27: Benefits Sensitivities

Benefits Sensitivities									
As of December 21, 2022									
Benefits Sensitivities	Base NPV ($M)		NPV ($M)		B/C Ratio	NPV ($M)		B/C Ratio	
			Favorable: +20%			Unfavorable: -20%			
Avoided Infrastructure Costs	$	464.3	$	557.2	7.0	$	371.4	6.5	
Reduced DER Curtailment	$	624.5	$	749.4	7.1	$	499.6	6.4	
Reduced Outage Frequency	$	377.1	$	452.5	7.0	$	301.7	6.6	
Whole House TOU/CPP	$	272.6	$	327.2	6.9	$	218.1	6.6	
VVO/CVR Benefits	$	582.5	$	699.0	7.1	$	466.0	6.4	
EV/TVR Benefits	$	130.9	$	157.0	6.8	$	104.7	6.7	
Utility O&M Savings	$	72.9	$	87.4	6.8	$	58.3	6.7	
Total Sensitivity - Benefits	$	2,524.7	$	3,029.7	8.1	$	2,019.8	5.4	

8.5.3 Combined Cost and Benefit Sensitivities

To examine the impact of a "worst case" scenario, Rhode Island Energy combined the Unfavorable Cost and Benefit Sensitivities. Figure 8.28 depicts the results of these combinations. As outlined in the chart, with the favorable combination, the benefit-cost ratio increases to 9.8 while the benefit-cost ratio of the unfavorable combination decreases to 4.6. Even in a "worst case" scenario, the GMP BCA results are very strong. These are compared to Base Case benefit-cost ratios of 7.5 from a Nominal perspective and 6.8 from an NPV ($2023) perspective.

Figure 8.28: Combined Cost and Benefit Scenarios

Combined Sensitivities					
As of December 21, 2022					
		NPV ($M)		NPV ($M)	
		Favorable		Unfavorable	
Total Benefits w/Sensitivities		$	3,029.7	$	2,019.8
Total Costs w/Sensitivities		$	309.5	$	438.0
Combined Sensitivities:	B/C Ratio	9.8		4.6	

8.5.4 Issue Specific Sensitivities

Rhode Island Energy performed two issue-specific sensitivities; one to look at the benefits and costs over a 10-year period rather than over the 20-year period that has been presented thus far. The purpose was to determine the viability of the program with a shorter time frame, particularly because the cost of the GMP is more front-loaded while the benefits come later in the analysis period. Nonetheless, the GMP still has a very solid benefit-cost ratio at 1.8 Nominal and 1.7 NPV ($2023). Figure 8.29 shows the results of the sensitivity.

Figure 8.29: Ten Year Sensitivity

10-Year Sensitivity		
As of December 21, 2022	Nominal ($M)	NPV ($M)
Total Benefits - First Ten Years	**$ 699.5**	**$ 534.1**
Total Costs - First Ten Years	**$ 390.4**	**$ 320.9**
Benefits Less Costs	**$ 309.1**	**$ 213.2**
B/C Ratio	**1.8**	**1.7**

The second issue-specific sensitivity revolves around the cost of carbon and the price used in calculating the Non-Embedded CO2 benefits. Rhode Island Energy made the decision to utilize the Social Cost of Carbon values developed by Synapse Energy as part of the AESC 2021 report. Traditionally, the Company has used the New England Marginal Abatement Cost (MAC) values to calculate similar benefits. The Company used the Social Cost of Carbon in both the AMF filing and in this GMP analysis. Figure 8.30 below shows the results of calculating the benefits with the New England MAC value rather than the Social Cost value. As can be seen in the chart, the benefit-cost ratios from both the nominal and the NPV ($2023) perspective remain extremely strong.

Figure 8.30: Cost of Carbon Sensitivity

Cost of Carbon Sensitivity		
As of December 21, 2022	Nominal ($M)	NPV ($M)
Total Benefits Using Social Cost of Carbon	**$ 3,946.9**	**$ 2,524.7**
Social Cost of Carbon Benefits	**$ 486.7**	**$ 376.2**
New England MAC Cost of Carbon Benefits	**$ 64.3**	**$ 51.9**
Total Benefits Using New England MAC	**$ 3,524.5**	**$ 2,200.4**
Total Costs	**$ 529.0**	**$ 373.8**
Benefits (NE MAC) Less Costs	**$ 2,995.4**	**$ 1,826.6**
Benefit/Cost Ration (NE MAC)	**6.7**	**5.9**

8.6 Alignment with Docket No. 4600

Many of the GMP functionalities and benefit impacts identified earlier in this document have been quantified using the Docket No. 4600 BCA methodology and inputs based on the detailed modeling. The source for many of the avoided cost value components is the "*Avoided Energy Supply Components in New England: 2021 Report*" (AESC 2021 Study) prepared by Synapse Energy Economics for AESC 2021 Study Group[90]. This report was sponsored by the electric and gas energy efficiency program administrators in New England and is designed to be used for cost-effectiveness screening in 2021 through 2023.

The GMP benefit category alignment with Docket No. 4600 benefits is presented in Figure 8.31.

Figure 8.31: Quantifiable GMP Benefit Category Mapping to Docket No. 4600 Benefits

Docket 4600 Framework categories quantified in the BCA model	
Docket 4600 Table	
22-Dec-22	
Docket 4600 Category	**GMP Benefits in BCA**
Power Sector: Distribution Delivery Cost	Communication Savings due to SS Fiber
	Reduced Curtailment: Energy Savings
	Utility O&M Savings
	Reduced VVO Lease Costs
	Avoided Infrastructure Cost - Distribution
Societal: GreenHouse Gas (GHG) Externality Cost	GMP - Total Non-Embedded CO2 Benefit: VVO/CVR
Societal: Non-GHG Externality Cost	GMP - Total Non-Embedded NOX Benefit: VVO/CVR
Societal: Public Health	GMP - Total Public Health Benefit: VVO/CVR
Power Sector: Energy Savings	Energy Savings: VVO/CVR
	GMP - Total Energy Shift Benefits: EV TVR
Power Sector: GHG Compliance Savings	Monetized CO2 Benefit: VVO/CVR
Power Sector: Retail Supplier Risk Premium	Not included because risk premium added into avoided costs.
Power Sector: Renewable Energy Credit (REC) Value	Not included because REC value added into avoided costs.
Power Sector: Distribution Savings	GMP Total Dist Capacity Benefit: Whole House CPP
	GMP - Dist Capacity Benefit: VVO/CVR
Power Sector: Capacity Savings	GMP - System Capacity Benefit: VVO/CVR
	GMP - Total System Capacity Benefit: EV TVR
	GMP - Total System Capacity Benefit: Whole House CPP
	GMP - Total System Capacity Savings: Whole House TOU

90 AESC 2021 Report, Synapse Energy Economics, Inc., Executive Summary, at 8, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf.

Power Sector: Transmission Savings	**GMP Total Trans Capacity Benefit: Whole House CPP**
	GMP - Trans Capacity Benefit: VVO/CVR
	Avoided Infrastrucuture Costs - Transmission
Power Sector: DRIPE Savings*	**GMP Total Capacity DRIPE Benefit: Whole House CPP**
Customer: Reliability & Resilience Impacts	**Reduced Outage Frequency Benefits due to FLISR**
Power Sector: Distribution Delivery Safety	**Safety for employees and public improved but not quantified**
Customer: Non-Participant Rate/Bill Impacts	**All Rhode Island Energy customers will benefit**
Power Sector - Transfer: Low Income	**Not Directly Captured; GMP will benefit all customers, including Low Income customers**
Societal: Cross-DRIPE Savings*	
Customer: Customer Bill Savings	**VVO savings creates customer bill savings**
Societal: Economic Development	**Brattle Group Report inidicates significant economic development benefits**
* Demand Reduction Induced Price Effect (DRIPE)	

8.7 Shared Cost Opportunities

To the extent there is an opportunity for cost sharing, Rhode Island will assess the applicability, and if the opportunity aligns with business needs, it will be pursued to benefit Rhode Island customers. Examples are provided below for possible cost share opportunities through The Infrastructure Investment and Jobs Act ("IIJA") and by advancing future infrastructure that would qualify as a Pool Transmission Facility through NEPOOL.[91]

IIJA: Rhode Island Energy has submitted Concept Papers to be considered for a grant under IIJA that was signed into law in November 2021. The law authorizes $1.2 trillion for transportation and infrastructure spending with $550 billion of that figure going toward "new" investments and programs. Funding from the IIJA is expansive in its reach, addressing energy and power infrastructure, access to broadband internet, water infrastructure, and more. Some of the new programs funded by the bill could provide the resources needed to address a variety of infrastructure needs at the local level. [92]

Pool Transmission Facilities: As discussed in Section 6, the fiber communication infrastructure is proposed as a shared distribution and transmission asset. The fiber transmission asset will be proposed through NEPOOL because it is a looped facility, where costs will be shared across the members. Rhode Island Energy's portion of this cost would be approximately 7% of the $23M because it is defined as a Pool Transmission Facility (PTF), based upon Rhode Island's load ratio share. In Section 5, there is also recommendation to perform additional study work to determine if converting a portion of the sub-transmission system to a higher voltage level and 115 kV expansion in Rhode Island offers additional efficiency and cost saving opportunities over the study period beyond that which has been identified through the Distribution Study. It is possible that the outcome from this analysis would result in

[91] https://nepool.com/ New England Power Pool ("NEPOOL")
[92] Infrastructure Investment and Jobs Act (IIJA) Implementation Resources (gfoa.org)

transmission facilities that would enjoy the same PTF treatment.

8.8 GMP BCA Conclusion

The BCA developed for the GMP was developed using Docket 4600 Guidance as discussed above. The GMP is necessary now to support the reliability and safety of Rhode Island Energy's grid, and in addition, the GMP shows significant benefits. Even after considering many different sensitivities, including a "worst case" sensitivity, the benefit-cost ratios for the GMP are significant. The GMP investments, particularly the Foundational Investments, are truly a "No Regrets" decision.

"No Regrets" is a phrase used in planning and BCA to indicate a decision or an investment that will be "used and useful" in virtually any future scenario that may emerge. It indicates that the decision maker will have "No Regrets" for having made that decision/ investment. Rhode Island Energy firmly believes that the Foundational GMP Investments requested in the GMP are "No Regrets" investments.
There are several reasons for this:

1. First and foremost, the Foundational Investments are ***needed now***. Lack of visibility and automation on Rhode Island Energy's system are significant barriers to operating the system reliably and safely, enabling customers to interconnect DER, and meet Rhode Island's Climate Mandates.
2. The Foundational Investments are designed to provide that visibility and automation.
3. The benefits, as demonstrated by the Benefit-Cost Analysis completed by the Company, show significant benefits to the Utility, Customers and Society. Many of these benefits will be realized regardless of the level of DER, EVs, and EHPs that are adopted.
    a. Increasing penetration levels of any of these technologies will only increase the benefits that can be realized.

Section 9

SECTION 9.0: CONCLUSION

Rhode Island customers want and deserve a forward-looking, leading-edge energy environment – one characterized by safe, reliable, affordable, and clean energy, with consumer choice, and poised to meet the State's Climate Mandates. Rhode Island Energy is prepared to and has an opportunity to deliver on these expectations with the Foundational Investments that solves operational challenges now and establishes a grid capable of achieving the Climate Mandates as detailed in this GMP proposal. The integrated solutions proposed as Foundational Investments in this GMP address operational challenges that are apparent today and provide capability to achieve various levels of DER adoption to achieve the Climate Mandates in the future. These solutions consider the current energy environment in Rhode Island, anticipate and extrapolate consumer and technological trends and advancements, and promulgate policies and engineering standards that will put Rhode Island Energy in the best possible position to deliver safety and reliability for its customers now and into the future.

How and when Rhode Island moves forward with grid modernization and other distribution infrastructure changes can have wide-reaching effects on reliability and safety, DG interconnection costs, availability of clean energy, and customer control over their energy use. The rate of policy and technological change occurring has a profound and complex impact on how grid resources operate and participate in the markets, how ISO-NE plans and runs the bulk power grid, and how consumers use and even pay for grid services. The interaction between consumers and the electric distribution system will continue to evolve as consumers become more dependent on and gain more control over their electricity supply, but the importance of reliable, affordable electricity to society's safety, comfort, and prosperity remains unchanged. [93]

Therefore, it is of the utmost urgency to act now and commence with the GMP investments. Anything less would be avoiding our present reality and failing to anticipate what we know is coming, rather than addressing current issues and anticipating far more significant issues in the near future, including declining system reliability, higher costs for consumers, and failure to achieve the Climate Mandates. There are many factors that are highlighted in this GMP that lead to the conclusion that the GMP investments are urgently needed, some of which include:

- Deteriorating reliability trends;
- Urgent need to gain visibility, situational awareness, and control of the electric distribution system;
- Increasing cost to consumers without GMP;
- Lengthening distributed generation interconnection queue;
- Increased safety and operational risk because of the presence of hidden load during switching;

[93] ISO-New England, *2019 Regional Electricity Outlook,* 9 (2019), https://www.iso-ne.com/staticassets/documents/2019/03/2019_reo.pdf

- Operational complexities such as voltage variability, protection vulnerabilities, and lack of situational awareness as evidenced during the August 2022 Nasonville event;
- Opportunistic conversions to advanced capacitor controls are not occurring at a rate that is keeping pace with the accumulation of DER on the system;
- High DER adoption rates that are reinforced with the Climate Mandates and various incentives;
- Mounting opportunity costs that will never be realized because DER interconnected today are not integrated in a way that they become mission-critical assets for safe and reliable grid operations; and
- A compromised supply chain, resulting in imminent delays for material availability.

The increased penetration of DER, reinforced by the Climate Mandates, has created additional system complexity that today's electric distribution system simply cannot handle. It requires adjustments to how the electric distribution system is used and operated to serve customers reliably and safely. This GMP explains the need for the Foundational Investments that are cost-effective to address electric distribution system issues caused by increasing customer DER adoption, deteriorating reliability, customers' evolving expectations, and the State's Climate Mandates. The analysis demonstrated that these investments are considered "No Regrets" in that they are required regardless of the future levels of DER penetration on the system. The GMP concludes that without these Foundational Investments:

1) Safety and reliability cannot be maintained due to the lack of visibility, situational awareness, and automated control of the distribution network given the two-way power flow conditions that are now being imposed on the system with higher levels of DER penetration; and
2) The Climate Mandates cannot be achieved even with massive transmission and distribution infrastructure buildout due to the amount of DER curtailment that would be required and the inability to monitor and control DER – Solar PV and storage batteries.

Factors that lead to the conclusion that the GMP Foundational Investments are urgent are presented in greater detail in Section 2. The No-Regrets Foundational Investments are required regardless of the future levels of DER penetration on the system, and they are needed as soon as possible for successful modern-day grid operations. The GMP also demonstrates that the quantitative BCA for GMP investments results in billions of dollars in net benefits for Rhode Island on a 20-year NPV basis. Additional qualitative benefits evaluated and described above only add to the quantified value. The prudency of the decision to proceed with the Foundational Investments is reinforced by having ADMS Basic operational software available at the TSA exit, which results in early benefits that are closely timed with the installation of advanced field devices and having increased confidence in the Rhode Island deployment plans based on PPL Electric's GMP deployment experience in Pennsylvania over the last decade.

The Company will be held accountable for progressing grid modernization foundational solutions by implementing a rigorous and accelerated plan with the appropriate oversight and transparency. Accountability measures will include annual reporting of key metrics, PUC review and approval of annual ISR plan investments, and continued engagement with the GMP/AMF Subcommittee. These measures will ensure the Company will be held accountable for deploying effective solutions and realizing customer benefits in a timely manner. The currently-filed AMF Business Case also provides its own portfolio of reporting, risk management, and benefits guarantee for the AMF investment.

Given the importance of DER Monitor/Manage to the success of this GMP, the Company is assessing the legal and regulatory approvals necessary to permit the Company to require UL-certified inverters to align with the latest IEEE 1547-2018 interconnection standard for Rhode Island Energy to fully embrace capabilities that the standard offers. As explained earlier in this GMP, the Company will make a separate filing for such approvals, including any tariff changes. Furthermore, because of the urgent need for the Foundational Investments, the Company has included these investments as non-discretionary investments in the FY 2024 Electric ISR Plan, which are substantiated by this GMP and accompanying BCA.

Transforming Rhode Island's electric distribution system is a journey that is urgently needed and may be undertaken as soon as it can be effectively implemented. It is important to take the next step in the journey now to ensure that the electric distribution system does not a) can continue to operate safely and reliably; b) does not prohibit customer empowerment; c) does not prohibit achievement of Rhode Island's Climate Mandate; and d) does not create higher costs for Rhode Island Energy customers. By delaying the GMP investments, there will be a wide range of detrimental impacts including worsening customer service, safety, and reliability, increased costs, affordability risks, added supply chain risks, delayed benefits, and challenges to enable a clean energy future. The Foundational Investments defined in this GMP have been included in the FY 2024 Electric ISR Plan as non-discretionary investments because the capability is needed now for safe and reliable operations.

Accelerated grid transformation is needed to manage system complexity that is caused by increased DER penetration and electrification that is already occurring and anticipated to grow significantly. Because of the current characteristics of the Rhode Island Energy electric distribution system, the Company believes it is not possible to continue to provide service reliably and safely with the status quo. GMP Foundational Investments have been defined as a "No Regrets" portfolio to address the operational, customer, and clean energy challenges of today. This portfolio of grid modernization investments is fully integrated, providing functionality that addresses present and future issues in order to successfully operate a modern-day grid with newfound system complexities. Not only are the GMP Foundational Investments critically needed for reliability and safety, but the overall results are also significantly positive from a BCA perspective using the Docket 4600 Framework.

For all of the reasons outlined in the GMP, the Company respectfully requests that the PUC accept this GMP and issue an order affirming that the Company has complied with its obligation to file a GMP that meets the requirements of the ASA.

Summary of Attachments

SUMMARY OF ATTACHMENTS

ATTACHMENT A:	**COMPLIANCE WITH RHODE ISLAND DOCKET 4600**
ATTACHMENT B:	**SUMMARY OF US GRID MODERNIZATION DEVELOPMENTS**
ATTACHMENT C:	**GMP ROADMAP: COMMUNICATIONS SOLUTIONS AND ASSUMPTIONS**
ATTACHMENT D:	**SYSTEM ISSUES NEGATIVELY IMPACTING DER PROJECTS**
ATTACHMENT E:	**GMP COMPARISON: NATIONAL GRID vs. RHODE ISLAND ENERGY**
ATTACHMENT F:	**DISTRIBUTION STUDY RESULTS BY PLANNING AREA**
ATTACHMENT G:	**DER MONITOR/MANAGE APPROACH AND FUNCTIONALITY**
ATTACHMENT H:	**GMP DEPLOYMENT PLAN**
ATTACHMENT I:	**GMP BENEFIT-COST ANALYSIS (BCA) SPREADSHEET**
ATTACHMENT J:	**CYBERSECURITY, DATA PRIVACY, AND DATA GOVERNANCE PLAN**
ATTACHMENT K:	**RHODE ISLAND ENERGY GRID MODERNIZATION LOSS STUDY**
ATTACHMENT L:	**IMPACT OF DISTRIBUTED GENERATION AND GRID MODERNIZATION ON VOLT-VAR OPTIMIZATION SYSTEMS**
ATTACHMENT M:	**EXAMPLE TRIGGERS FOR NCRI DISTRIBUTION STUDY FIXES**
ATTACHMENT N:	**ACRONYM LIST**

Attachment A

ATTACHMENT A

Compliance with Rhode Island Docket 4600

GMP Alignment with Docket No. 4600 Principles

Rhode Island Energy's GMP is in full alignment with goals and principles enunciated by the Commission in Docket No. 4600. In that proceeding, the Commission adopted a set of goals, rate design principles, and a new Rhode Island benefit-cost framework for use in future dockets.[1] The Docket 4600A Guidance Document discusses the application of each element and specifies that any proponent of a program proposal with associated cost recovery will need to explain how a new program or capital investment advances, detracts from, or is neutral to the Docket 4600 goals. The application of the Docket 4600 Framework is further discussed below.

According to the Commission's directive, the 4600 Framework should serve as a starting point in making a business case for a proposal, but also makes clear that it should not be the exclusive measure of whether a specific proposal should be approved.[2] The PUC recognized that there may be outside factors that need to be considered regardless of whether a specific proposal is determined to be cost-effective or not, such as statutory mandates or qualitative considerations, and that such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates. Similarly, Rhode Island Energy's statutorily-imposed duties as a chartered public utility includes an affirmative obligation to provide safe, adequate and reliable service.[3] For the remaining components of the GMP Business Case, the benefits and costs are evaluated holistically, and the demonstrated alignment with the Commission's goals and objectives are centered on GMP's functionalities and outcomes needed to operate a Modern-day grid, for customers to easily integrate DERs and reduce their electricity consumption, and for the State of

[1] *See* Report and Order No. 22851 at 6, 29.
[2] *Id*. at 23
[3] RIGL Section 39-2-1.

Rhode Island to meet the Clean Energy Mandates. The GMP will improve outage detection and restoration timeframes, especially when enhanced with AMF information which provides grid-edge sensing capabilities for improving system reliability through operational advancements such as a Distributed Energy Resource Management System (DERMS). Time-Varying Rates (TVR), enabled by AMF, can encourage customers to reduce energy demand and consumption through actionable and timely data, which will be critical for responding to the growing peak loads that are largely caused by beneficial electrification from the increased demand from charging electric vehicles and heating conversions.

A complete assessment of how GMP aligns with Commission's vision for the future electric system is listed in Figure A.1 below:

Figure A.1: Alignment Between Docket No. 4600 Goals and GMP Investments

Goals For "New" Electric System	Advances?/ Detracts From?/ Is Neutral To?
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances: The Company's GMP investments are foundational enablers necessary to efficiently and cost-effectively manage two-way power flows in a reliable, safe, clean and affordable manner. The GMP's top priority is to ensure the electric distribution grid continues to operate within compliance of planning criteria and service quality standards, but also to leverage opportunities to optimize performance to enhance customer benefits where they are cost effective. Specifically, GMP investments can reduce customer energy use and distribution system capacity requirements directly through voltage optimization and conservation voltage control schemes (i.e., VVO/CVR), which enables the operation of distribution feeders at lower overall voltages to reduce electricity consumption and peak demand from customer appliances. Grid modernization investments coupled with AMF can contribute to incremental benefits in this area by integrating granular AMF voltage data into VVO/CVR control schemes. In addition, AMF will enable customers to become more active in managing and reducing their energy usage through enhanced energy use insights (e.g., AMF-based High Bill Alerts) or integrating AMF with in-home technologies. GMP investments will also avoid multiple utility costs, thereby creating the possibility of improved affordability for Rhode Island customers, including

	better management of: • Distribution system O&M costs • Distribution system infrastructure capital costs • Transmission system infrastructure capital costs • Bulk energy purchases In addition, GMP investments can reduce customer outage restoration times through the addition of advanced reclosures, breakers, and fault location, interruption, and service restoration (FLISR) control schemes. AMF has the potential to increase reliability further by enabling better outage management and reduced outage notification times due to autonomous meter outage notifications, which allow field personnel to restore power more quickly without relying on customer calls and substation monitoring.
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	<u>Advances:</u> The GMP investments will help more Rhode Island customers reduce their energy costs and earn additional revenue by enabling them to invest in their own DER technologies in areas that are most cost-effective for these resources. In addition, GMP construction spending will create additional jobs in Rhode Island. Indirectly, GMP impacts are felt in the local supply chain, since industries are providing goods and services for the GMP implementation. Induced impacts are felt mainly in the local service sector, such as increased retail activity and hiring as the direct and indirect workers spend a portion of their incomes locally.
Address the challenge of climate change and other forms of pollution	<u>Advances</u>: GMP investments will reduce greenhouse gases (GHGs) and other harmful emissions by enabling reduced energy use (e.g., VVO/CVR, High Bill Alerts) and renewable DG curtailment. The investments will also enable more cost-effective interconnection and better utilization of clean DERs (e.g., solar DG, EVs, EHPs) into the electric distribution grid, which will reduce Rhode Island's reliance on more carbon-intensive energy technologies. Finally, additional emissions reductions will be realized due to a reduction in utility "truck rolls" resulting from improvements in operational efficiency.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	<u>Advances</u>: Grid modernization investments can reduce DER interconnection costs and enable improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes, provide flexible interconnection options, reductions in time to interconnect, and better customer and third-party information sharing and services. By reducing costs and other barriers to interconnect, grid modernization will help more Rhode Island customers invest in their own DER technologies in areas where these technologies are most cost-effective. In addition, AMF will provide more granular energy usage data to enable customers to better understand and choose among DER offerings (i.e., DG storage, EV, DR, and Energy Efficiency solutions) to better manage their energy usage and costs.

	Specifically, GMP investments will facilitate cost-effective customer investment in DERs by enabling: • Load optimization to relieve thermal or voltage constraints due to DER adoption rather than relying on traditional "wires-based solutions" • Improved efficacy of Energy Efficiency and DR programs by providing more granular data to customers (e.g., detailed billed energy use, in-home displays) • third-party programs and offerings that will drive innovation and provide additional value to customers, while encouraging new industry participants to enter the market with new customer offerings • Savings on EV charging costs by virtue of future time-varying pricing that incentivize customers to displace EV charging to off-peak times • Higher hosting capacity on the distribution system to accommodate higher penetrations of DERs at lower cost • More cost-effective DER investment due to system information sharing via the System Data Portal • A distributed energy resource management system (DERMS), in combination with an Advanced Distribution Management System (ADMS) and other GMP investments for DER Monitor / Manage that is coupled with AMF, will enable optimization of DER output (e.g., reduced DER curtailment) and provide the necessary information, operations and settlement services to DER providers, which are required to efficiently integrate DER into the distribution system.
Appropriately compensate the distribution utility for the services it provides	Advances: The ability to monitor two-way power flows will allow the Company to better understand the impacts of DER and assess the value that the grid provides to both consumers (i.e., rate payers) and producers (i.e., DER customers) and with this enhanced understanding the Company should be better positioned to develop innovative and appropriate rates.
Appropriately charge customers for the cost they impose on the grid	Advances: The GMP does not propose utility revenue requirements, cost allocation or rate design at this time. However, per the ASA, the AMF Business Case and this GMP includes assumptions to develop a future time varying rate proposal. System information provided by GMP and AMF-enabled time varying rates will establish opportunities for new pricing and allocation mechanisms to attribute costs more equitably.

Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances: The GMP includes a detailed BCA that is aligned with the Docket No. 4600 regulatory framework in order to better align distribution utility, customer, and policy objectives. In addition, specific GMP investments will provide input into the System Data Portal to provide transparency concerning system needs and opportunities for interested stakeholders, thereby fostering a more collaborative approach to distribution system planning and operations. Customer enablement is achieved through AMF which provides improved customer data access through the Customer Portal (CP) and Home Area Network (HAN), as well as facilitating easier data sharing among customers and third parties using Green Button Connect (GBC). When coupled with future rate designs and incentives, AMF also aligns customer and utility interests with policy objectives by providing customers with greater choice and control over energy usage while providing the Company with better visibility of its distribution system, leading to a cleaner, more efficient electric distribution grid. Finally, stakeholder engagement has been a large component of the GMP and AMF filings and through this forum, the Company and stakeholders have worked to ensure customer and policy objectives and interests are addressed. Through this GMP, the AMF Business Case, and future regulatory filings, the Company will continue to align grid modernization with customer, distribution utility, and policy objectives and interests.

Mapping of Docket 4600 Benefit Categories to the AMF BCA

Figure A.2 lists each category of the Docket 4600 Framework and indicates if the category is quantified in the benefit cost analysis contained in Section 8. The manner in which categories either are factored into the BCA or omitted appears in the rightmost column.

Figure A.2: Benefit categories included in the Docket 4600

4600 Level	Benefit Category	Quantified in Filing?	Treatment in GMP BCA or Reason for Exclusion
Power Sector Level	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Yes	Included in VVO/CVR savings and Reduced DER Curtailment using AESC values
	REC Value	Yes	Included indirectly through AESC values in VVO/CVR and Reduced DG Curtailment
	Retail Supplier Risk Premium	Yes	8% supplier markup included in VVO/CVR and Reduced DER Curtailment benefit calculations
	Forward Commitment Capacity Value	Yes	Included in Reduced System Capacity Requirements as Generation Capacity Savings; assumes 3-year lag
	Forward Commitment: Avoided Ancillary Services Value	No	Likely small impact
	Electric Transmission Capacity Value	Yes	Included in Avoided Infrastructure Costs and Transmission Capacity Savings
Power Sector Level	Net Risk Benefits to Utility System Operations from DER Flexibility & Diversity	Yes	Included in Avoided Infrastrucutre Costs, Reduced DER Curtailment and enhanced flexibility on the system to prevent outages and reduce outage length
	Option Value of Individual Resources	No	Difficult to accurately quantify at this time.
	Investment Under Uncertainty; Real Option Value	Yes	ISR Grid modernization Foundational Investments are needed now and under any future DER/EV/EHP penetrations
	Energy Demand Reduction Induced Price Effect (DRIPE)	Yes	Included in Whole House CPP benefit calculation. Not included in other calculations due to small impact
	GHG Compliance Costs	Yes	Included in VVO/CVR benefit as Monetized CO2 costs.
	Criteria Air Pollutant and Other Environmental Compliance Costs	No	Likely small impact. Did calculated Non-Embedded NOx values and non-embedded Public Health savings.
Power Sector Level	Innovation and Learning by Doing	Yes	The Distribution Study used in developing Avoided Infrastructure Costs is a leading-edge approach to distribution planning that is needed for a modern grid.
	Distribution Capacity Costs	Yes	Included in Avoided Infrastructure Costs, VVO/CVR Benefit, and Whole House CPP Benefit.
	Distribution Delivery Costs	Yes	Included as O&M savings.
	Distribution System Performance	Yes	Benefits from VVO/CVR, Reduced Curtailment, Reduced Outage Frequency, Reduced System Capacity requirements, ability of system to handle significant increases in DERs, EV, and EHP.
	Utility Low Income	Yes	Included in O&M savings, TOU/CPP options and Avoided Infrastructure costs.
	Distribution System and Customer Reliability/Resilience Impacts	Yes	Included in Reduced Outage Frequency
	Distribution System Safety Loss/Gain	No	Benefits not directly measured but GMP investments needed for both Customer safety (reduced outages) and employee safety (better visibility with switching operations.)

4600 Level	Benefit Category	Quantified in Filing?	Treatment in GMP BCA or Reason for Exclusion
Consumer Level	Program Participant/Prosumer Benefits	Yes	Reduced DER Curtailment, Whole House TOU/CPP, Electric Vehicle TVR
	Participant non-electric benefits; oil, gas, water, waste water	No	Not applicable to GMP investments. For example, incremental EV and EHP adoptions may result from improved ability to facilitate home charging and heat pumps but gasoline and oil savings and incremental costs were excluded from the analysis to avoid double-counting with EV initiatives.
	Low-Income Participant Benefits	Yes	Included in O&M savings, TOU/CPP options and Avoided Infrastructure costs.
	Consumer Empowerment & Choice	Yes	Included in TOU/CPP options and Electric Vehicle TVR options.
	Non-participant Rate and Bill Impacts	Yes	Included in Reduced O&M savings, Avoided Infrastructure Costs and VVO/CVR
Societal Level	GHG Externality Cost	Yes	Included in VVO/CVR. Not included in Reduced Curtailment (although calculated) because those benefits may be included in other programs.
	Criteia Air Pollutant and Other Environmental Externality (	Yes	Included in VVO/CVR. Not included in Reduced Curtailment (although calculated) because those benefits may be included in other programs.
	Conservation and Community Benefits	No	Likely small impact.

Attachment B

ATTACHMENT B

Summary of US Grid Modernization Developments

Nearly all new generation added to the electric system today and in the future is renewable – primarily on and off-shore wind, solar PV (ground mounted and roof top), and storage batteries. In addition to renewable generation the grid is expected to accommodate beneficial electrification of many types to satisfy clean energy objectives. Because of safety and reliability concerns with the lack of situational awareness and control of the distribution system given these rapidly emerging trends, most utilities are rapidly planning and deploying AMF and grid modernization investments to satisfy operational, customer and clean climate objectives. Many have implemented foundational grid modernization investments and achieved significant reliability benefits and the capability to recover faster from major events from them.[1]

The three major ambitions defining the future electric grid—decarbonization, grid reliability/ resiliency, and customer involvement—all of which can be achieved through intelligent investment in AMF and grid modernization investments to provide functionality to address the challenges presented by a modern-day grid. If managed correctly, distributed energy resources (DER)—including rooftop solar photovoltaic (PV) systems, electric vehicles (EV), energy storage, demand response, and grid-connected, controllable loads—can play a significant role in supporting these ambitions by providing beneficial services to customers and the grid.

The full value of those services cannot be achieved, however, unless the emerging modern-day grid is empowered to handle DER. The urgency of these efforts is growing as DER adoption accelerates, driven by reliable and safe operations, improving economics, and increasing customer

[1] Oak Ridge National Laboratory, UT-Batelle for the U.S. Department of Energy, *Analysis of EPB of Chattanooga Smart Grid Investment* (June 2017), https://info.ornl.gov/sites/publications/Files/Pub74732.pdf

interest in reducing energy bills. DER adoption has been increasing throughout the past decade, a trend that is likely to accelerate:

- Behind-the-meter solar in the U.S. is projected to increase from 40 gigawatts in 2020 to 70 gigawatts by 2025.[2]
- Behind-the-meter energy storage in the U.S. is projected to increase from 1 gigawatt in 2020 to 7 gigawatts in 2025.[3]
- About 1.8 million EVs have been sold in the U.S. as of February 2021, representing about 4.5 terawatt-hours of movable, annual load.[4] The growth in electric vehicles (EVs) and hybrid electric vehicles (HEVs) is climbing and by 2025, EVs and HEVs will account for an estimated 30% of all vehicle sales.[5]

Along with accelerating DER adoption, several factors are converging to drive efforts to integrate DER into the grid:

- **Federal and state policies:** In April 2021, the Biden administration pledged to reduce U.S. economy-wide carbon emissions to about 50% below 2005 levels by 2030. Because the transportation sector and buildings can significantly reduce carbon emissions through electrification, the power sector will play a crucial role in achieving the administration's goal. More than 20 states have established economy-wide greenhouse gas emissions targets with specific goals to reduce emissions by a specific amount by a pre-determined date. Many states and jurisdictions also have established targets for renewable energy, EVs, and energy storage. DER deployment will be an important part of achieving these targets.

[2] Wood Mackenzie, U.S. solar forecasts data tool. Note: Behind-the-meter solar includes installed capacity in the residential, commercial, government, nonprofit, and community solar segments
[3] Wood Mackenzie, energy storage forecast data tool. Note: Behind-the-meter storage includes power capacity in the residential, commercial, industrial, education, military, and nonprofit segments.
[4] EPRI analysis of IHS and Polk sales data
[5] "Driving into 2025: The Future of Electric Vehicles," J.P. Morgan (October 10, 2018), https://www.jpmorgan.com/insights/research/electric-vehicles

- **Customer expectations:** Customers expect more from utilities, including cleaner energy, personalized services, real-time information on outages, and the ability to install smart appliances and easily connect solar, energy storage, and EVs to the grid. Many customers see DER as an avenue to address these goals and expect utilities to accommodate them.
- **Climate change:** The increasing frequency of extreme weather events has made customers more interested in resilience and on-site, backup power during outages—and has increasingly driven adoption of both rooftop solar and energy storage.[6]
- **State grid modernization activities:** In the second quarter of 2022, 48 states plus DC took a total of 549 policy and deployment actions related to grid modernization, utility business model and rate reform, energy storage, microgrids, and demand response.[7] The most notable actions included, the filing of new tariffs in Arizona, the completion of an energy storage study in Illinois, the enactment of energy storage and resilience legislation in Colorado and the release of a straw proposal on reliability and resilience program frameworks in Connecticut. Figure B.1 provides a summary of state and utility actions on these topics.[8] Figure B.2 provides a more detailed summary of the actions summarized in Figure B.1.[9] Some states, such as California and New York, are several years into comprehensive modernization efforts and are deploying new technologies to operate the grid and developing processes to integrate DER.
- **Market changes:** In 2020, FERC approved Order 2222, which requires regional distribution system operators to revise their tariffs to allow DER to participate alongside traditional generation resources in wholesale energy markets. Companies that aggregate

[6] EPRI technical staff communications with various utilities and vendors [more detail available from Nick T]
[7] NC Clearn Energy Technology Center, 50 States of Grid Modernization, Q2 2022 Quarterly Report July 2022 - Q22022_gridmod_exec_final.pdf (ncsu.edu)
[8] NC Clearn Energy Technology Center, 50 States of Grid Modernization, Q2 2022 Quarterly Report July 2022 - Q22022_gridmod_exec_final.pdf (ncsu.edu)
[9] NC Clearn Energy Technology Center, 50 States of Grid Modernization, Q2 2022 Quarterly Report July 2022 - Q22022_gridmod_exec_final.pdf (ncsu.edu)

energy storage, rooftop solar, demand response, EVs, and other DER can receive compensation in energy markets for grid services.

- **Integrated distribution planning**: Regulators are considering more comprehensive distribution system planning requirements—often called integrated distribution planning (IDP)—that involve coordination with transmission and generation planning. IDP requirements can include new analytical capabilities to enhance DER integration as well as assessment of the amount of DER that the grid can accommodate.
- **Grid asset utilization:** Distribution system operators are interested in optimizing the use of existing distribution grid assets. Deploying DER and managing them effectively can increase asset utilization, providing an alternative to traditional grid infrastructure upgrades.

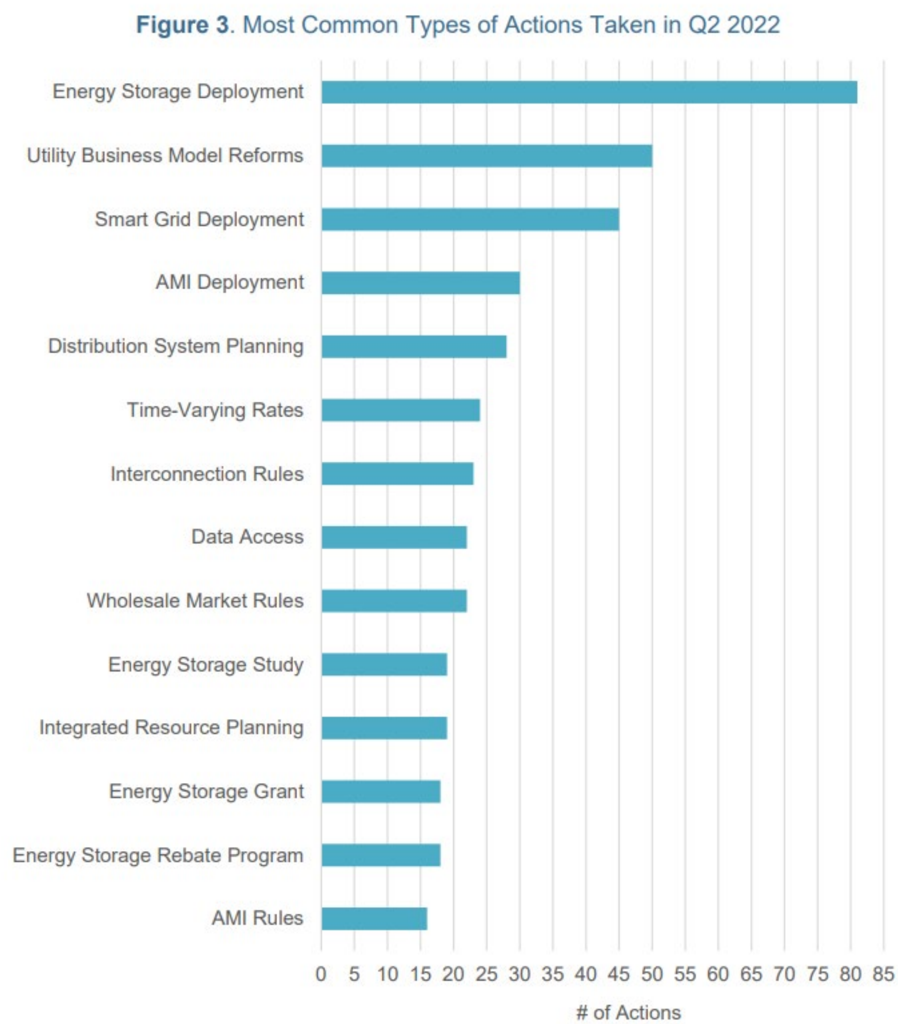
Figure B.1 Summary of Grid Modernization Actions by States and Utilities Q2 2022

Table 1. Q2 2022 Summary of Grid Modernization Actions

Type of Action	# of Actions	% by Type	# of States
Deployment	130	24%	37
Policies	97	18%	29 + DC
Financial Incentives	95	17%	31
Business Model and Rate Reform	87	16%	37 + DC
Planning and Market Access	78	14%	27 + DC
Studies and Investigations	62	11%	28 + DC
Total	**549**	**100%**	**48 States + DC**

Note: The "# of States/ Districts" total is not the sum of the rows because some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure B.2. Most Common by States and Utilities Q2 2022



Along with their potential benefits, DER can also have significant negative impacts on the grid. They can increase variability in power flow patterns and in grid energy supply and demand. They can also adversely impact key grid parameters such as voltage and frequency. These changes can potentially lead to damage in grid and customer assets and can challenge grid reliability, stability, safety, and resilience. The grid impacts of DER will vary by location, depending on factors such as DER penetration, geographical layout, the condition of grid assets, and the size and profile of the customer load. There have been several well-attested cases where expansion of DER without thoughtful planning and operational control has led to significant adverse impacts on grid reliability. An often-cited example is Germany, where the rapid proliferation of customer-sited solar PV occurred without consideration for how those resources were to be integrated with the existing power system, resulting in local overvoltage, or loading issues, and reduced reliability, quality and affordability of electricity. Fortunately, many of the inverters deployed in these PV systems had communications capabilities that enabled distribution system operators to curtail generation and mitigate grid impacts.[10] In one well-documented instance in the United Kingdom in August 2019, a major outage occurred that could have been prevented if the distribution system operator had better control over 500 megawatts of distributed generation that suddenly went offline.[11] The recent Rhode Island Energy outage at Nasonville provides an example closer to home where situational awareness and grid modernization equipment would have reduced to impact and cost of the outage.

The impacts will also vary with the type of DER and how they are operated. While distributed solar PV systems have had the greatest impact on the grid to date, many other types must also be considered. EVs, an essential part of economy-wide carbon reduction plans, may present challenges to distribution system operators as charging loads increase, particularly if charging is not managed during peak demand. Flexible, grid-interactive loads such as HVAC systems can be used to manage overall grid load, but this must be done without compromising customer comfort and convenience. Distributed energy storage can help balance load and generation and can provide resilience to customers but charging and discharging must be managed carefully to avoid adverse impacts on the distribution or transmission grids. In addition to each having their own effect, these

[10] "The Integrated Grid: Realizing the Full Value of Central and Distributed Resources," EPRI, Palo Alto, CA, 2014.

[11] "National Grid ESO Technical Report on the Events of 9 August 2019," (Issued Sept. 6, 2019), https://docslib.org/doc/791969/national-grid-eso-technical-report-on-the-events-of-9-august-2019

different kinds of DER can interact with each other to mitigate or intensify grid impacts, depending on how they are controlled causing performance characteristics of a Modern-day grid.

Rhode Island Energy is not the only utility facing the challenges of an evolving energy landscape. In January 2019, Smart Electric Power Alliance (SEPA) released a report titled "Understanding and Evaluating Potential Models for the Future Electric Power Utility"[12] , which drew upon key insights from their 51st State Initiative Phase III Summary Report. Most utilities today operate by being primarily reactive to DER deployment, facilitating interconnection and integration to maintain reliability and power quality, but not by proactively encouraging DER deployment or controlling dispatch. This reactive "DER Interconnection and Integration" business model, as SEPA labels it, can be adjusted to ensure robust market competition, innovative offerings from third parties, and consumer choice. However, a key challenge to this reactive model is that it may miss opportunities to create value for individual customers and collectively through the grid.

According to the U.S. Department of Energy (DOE), today's electric grid lacks "the attributes necessary to meet the demands of the 21st century and beyond."[13] Grid modernization, then, would refer to any and all efforts to bring the electricity grid into alignment with current and future needs. While the term has been used to encompass a broad array of initiatives, common themes include improving the grid's responsiveness, interactivity, and resilience.[14] Drivers of grid modernization across the country include emerging technologies, evolving consumer demands, cybersecurity concerns, extreme weather events, and a broadly shared desire – among utilities, regulators, policy makers, and the public – to reduce the greenhouse gas (GHG) emissions associated with electricity production and support the development of low-carbon energy infrastructure.

[12] Understanding and Evaluating Potential Models for the Future Electric Power Utility, SEPA (2019), https://sepapower.org/resource/understanding-and-evaluating-potential-models-for-the-future-electric-power-utility

[13] https://www.energy.gov/grid-modernization-initiative

[14] https://www.energy.gov/grid-modernization-initiative 3 https://nccleantech.ncsu.edu/wp-content/uploads/2019/05/Q12019_gridmod_exec_final.pdf

Interest in grid modernization among utilities and utility regulators has increased in recent years. Because it involves identifying and prioritizing a suite of near-term investments in new and emerging technologies to enable unprecedented capabilities in an uncertain future, grid modernization is among the most complex challenges that utilities, regulators, and stakeholders grapple with today. Consequently, the Company's efforts to address grid modernization in Rhode Island, and the leadership shown by the Rhode Island PUC in this area, are of national interest and significance.

Notable recent grid modernization developments in other states include:

- Virginia regulators approved Dominion Energy's 10-year plan to transform the electric distribution grid. The ruling approved $650 million of investments in 2022 and 2023. The investments include the company's Advanced Metering Infrastructure (AMI) proposal, the development of a customer information platform, grid infrastructure and technology, telecommunications and cyber security.[15]
- The New Mexico Energy Minerals, and Natural Resources Department released its grid modernization roadmap; the roadmap serves as a guide to electric service providers, regulators, policymakers and consumers as New Mexico transitions to 100 percent zero-carbon electricity resources by mid-century in accordance with the Energy Transition Act of 2019.[16]
- New Jersey regulators approving Jersey Central Power & Light's AMI deployment. The meter deployment is scheduled to begin in 2023 with completion in 2026.[17]

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[15] The 50 States of Grid Modernization Q1 2022: States Focus on Promoting Grid Resiliency During Q1 2022 | NC Clean Energy Technology Center (ncsu.edu)
[16] Grid Modernization - Energy Conservation and Management (nm.gov)
[17] The 50 States of Grid Modernization Q1 2022: States Focus on Promoting Grid Resiliency During Q1 2022 | NC Clean Energy Technology Center (ncsu.edu)

- In Ohio, First Energy filed an application for approval of the second phase of its distribution grid modernization plan ("Grid Mod II") in July 2022. The $626.4 million plan includes investments in advanced metering infrastructure, distribution automation, an advanced distribution management system, and a distributed energy resource management system, among other investments.[18]
- Massachusetts lawmakers enacted H. 5060 in August 2022, which requires utilities to develop electric sector modernization plans. The plans must focus on transmission and distribution system upgrades to improve grid reliability, resiliency, and adoption of renewable energy and distributed resources, among other goals. The bill also established a grid modernization advisory council, which will provide input on the modernization plans.[19]

Other notable work by utilities in grid modernization efforts include:

- PPL Electric Utilities was named the 2019 SEPA Power Players Investor-Owned Utility of the Year by the Smart Electric Power Alliance (SEPA). The award was a recognition of the company's comprehensive plan and strategy to prepare for the future by creating the next generation of advanced distribution management system functionalities through its Distributed Energy Resource Management System (DERMS)."[20] The DERMS system dynamically manages DER connected to PPL's grid to optimize power quality, while encouraging the adoption of DER like solar. The DERMS enables PPL to host more interconnected DER because it leverages these resources to counteract some of the negative impacts that DER can have in high penetrations (such as causing high line

[18] NC Clearn Energy Technology Center, 50 States of Grid Modernization, Q3 2022 Quarterly Report October 2022 – Q32022_gridmod_exec_final.pdf (ncsu.edu)
[19] NC Clearn Energy Technology Center, 50 States of Grid Modernization, Q3 2022 Quarterly Report October 2022 – Q32022_gridmod_exec_final.pdf (ncsu.edu)
[20] SEPA's 2019 Power Player Award Winners | SEPA (sepapower.org)

voltage or over-operation of capacitor banks). PPL has made significant investments in grid automation over the past decade, such that outages were down 30% in 2020 compared to 2010.[21]

- Over the last few years, powerful storms in Chattanooga were costing the utility $100 million per year. To address this issue, EPB fast tracked their grid modernization program by deploying a comprehensive community-wide fiber optic network accessible to every home and business in the utility's 600 square mile service area.[22] EPB's fiber optic network became the primary means of communication for all smart grid equipment. They invested in an advanced metering infrastructure system that included the deployment of smart meters, an energy management web portal, and distribution automation equipment. The project also delivered time-based rate programs to customers to create incentives for peak load reductions. The savings attributed to the grid modernization investments includes savings in operational costs through automated meter reading, savings for eliminating the need to manually operate switches, reduction in outage duration, and savings in wholesale demand through voltage controls.[23]

As this summary shows, grid modernization is a complex, wide-ranging issue (or set of issues) that utilities and commissions have approached in different ways. It is possible, however, to identify common themes of successful efforts. These include the establishment of a strong value proposition; a clear vision for proposed investments, expressed in a detailed roadmap; robust stakeholder engagement; and utility accountability for delivering results. All of these elements have been incorporated into the Rhode Island Energy GMP.

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[21] R.I. grid sale a rare opportunity, clean energy advocates say | Energy News Network

[22] Chattanooga's smart grid prevented around 44,000 customers from losing power | American Public Power Association

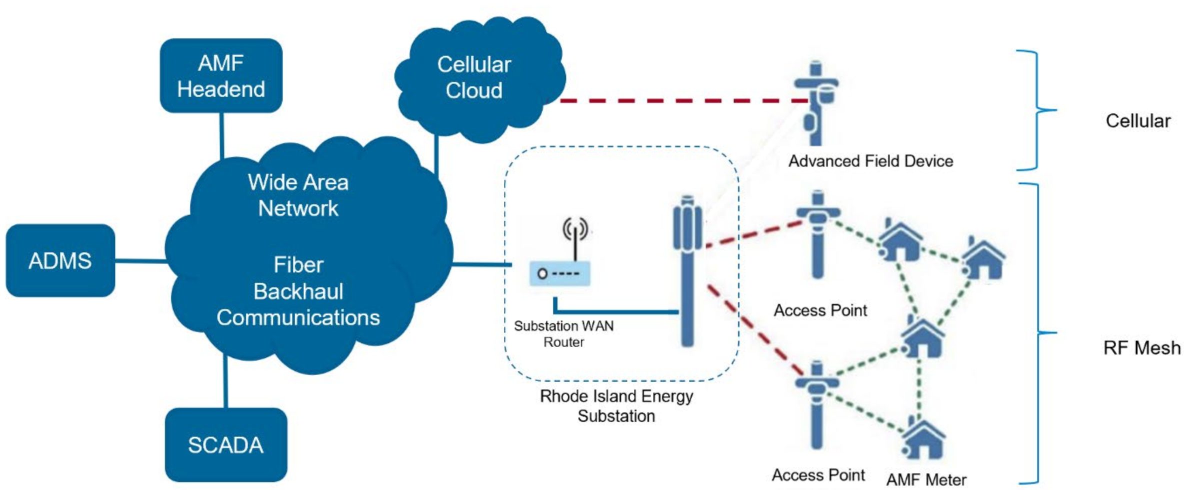
[23] Outsmarting Storms in Chattanooga | Grid Modernization Lab Consortium (doe.gov)

ATTACHMENT C

GMP Roadmap: Communications Solutions and Assumptions

Communications is a solution needed by all GMP functionalities. This attachment identifies, describes, and examines the pros, cons, and assumptions (basis for the BCA) of all the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities. As depicted below and first introduced in Section 6.5 – GMP Roadmap Communications, Fig. C.1 illustrates Rhode Island Energy's proposed communication system to support the GMP. This communication system encompasses the expansion of existing systems including SCADA and cellular to connect advanced field devices, as well as a significantly expanded fiber backhaul system connecting all substations, and the proposed RF Mesh Network that will connect all new digital meters (proposed in the AMF Filing).

Figure C.1: Communication System with Fiber Backhaul



Communications technologies that support GMP and AMF utilize a variety of communication methods to monitor and control the distribution networks in real time. Communications to/from DERs, Advanced Field Devices and with devices in the substation are all critical because status monitoring of the system and equipment plays an important role in grid modernization. The communication solutions to support needs for GMP (and AMF) have been divided into three areas which are each discussed in greater detail below:

1) Meter and customer enablement including DER Monitor / Manage
2) Advanced Field Devices
3) Backhaul Communications

Communications for Customer Enablement Including DER Monitor / Manage

AMF includes building a private RF mesh system to support meter reading and Customer enablement as described in the AMF filing Section 5. Distribution system operators (DSO) will need to have the capability to monitor activities of DERs in the wholesale market and take action to curtail if such distributed generation sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced ability to monitor and manage DER as described in Attachment G. At this point, it is not clear how communication costs to allow DER market participation will be effectively allocated and recovered. What is clear, is that the Company needs to have monitor and control capability of DERs to make a difference at the system level in terms of managing load with generation, and fully integrating DER with the operations. The ability to monitor and manage DER is helpful for the entire system and therefore, should be shared by all customers[1].

[1] See DIV 2-15 data response.

Communications with DERs need to be two-way to monitor and change settings, low cost, and have the capability to interact with a high volume of points. Communication alternatives that could be considered for DER Monitor / Manage communications include cellular, Private RF Mesh AMF communications, and Public WiFi (either through an aggregator or direct by Rhode Island Electric). Below are pros and cons, along with the assumptions included in this GMP.

Figure C.2: DER Monitor / Manage Possible Communication Solutions and Assumptions

Technology	Pros (+) and Cons (-)	GMP Assumption
Public Cellular	+ Availability + Secure network + Bandwidth availability - Affordability - Scalability	
Private RF Mesh	++ Availability + Secure network - Bandwidth availability + Affordability + Scalability	• Assumed DER Monitor / Manage solution[2] uses Company-owned RF mesh • BCA assumes DER Monitor/Manage will utilize the AMF RF Mesh for communications. There is no cost • New DER being interconnected will participate • Program was assumed to start mid 2026

[2] Near-term assumption is that large DER requires dedicated RTUs at the Point of common Coupling that will continue to require cellular communications given the complexity and potential bandwidth requirements that will be needed for these sophisticated installations. Efforts will occur over the GMP horizon to move as much as possible to the RF Mesh system. Cellular costs for these installations are in the RTB today, and therefore, are included in the With Grid Modernization and Without Grid Modernization alternatives, but not in the BCA.

		• $0 incremental communication cost were included because AMF network would be available to provide communication services.
Public WiFi	- Availability - - Secure network - Bandwidth availability + Affordability - Scalability	

Communications for Advanced Field Devices

Advanced Field Devices have a different communication requirement than DER Monitor / Manage and for AMF meters. These devices are relatively sparse in nature and geographically dispersed, yet communications need to be secure, and while there is autonomous functional capability, operations is ADMS-dependent. The architecture that provides PPL with capabilities uses state-of-the-art centralized intelligence where the analytics is coming from inputs from the Advanced Field Devices and algorithms located in ADMS and supporting operational systems that are applied to the network model. As a result, as the distribution system becomes more dynamic over time, the architecture can accommodate operational needs of an increasingly fluid system, enabling capability such as dynamic protection. While there are relatively few Advanced field devices, the communications between them and ADMS needs to be secure, dependable and is time sensitive. However, the volume of devices to be supported is very different from AMF and that of other emerging customer-side technologies.[3] The communication alternatives that could be considered for Advanced Field Devices include Public Cellular, Private RF Mesh AMF communications, and Fiber. The pros and cons are below along with the assumptions that have been included in this GMP.

[3] Communications for AMF meter data is every 15 minutes; however, alarms are configurable and can be reported immediately after being detected.

Figure C.3: Advanced Field Devices Possible Communication Solutions and Assumptions

Technology	Pros (+) and Cons (-)	GMP Assumption
Public Cellular	+ Availability - Secure / Resilient network + Bandwidth availability + Latency + Affordability + Scalability	• Assumed public cellular for Advanced Field Devices. • Requires an O&M lease cost for each device, • Cellular communications will be available at the time the Advanced Field Device is commissioned. This is consistent with PPL Electric installation procedures. • Advanced reclosers go in-service beginning in 2024; Advanced capacitors and regulators go in-service beginning in 2024. Advanced microprocessor relays go in-service beginning in Spring 2024.
Private RF Mesh	+ Availability + Secure / Resilient network - Bandwidth availability - Latency + Affordability - Scalability	
Fiber	- Availability + Secure / Resilient network + Bandwidth availability - Affordability - Scalability	

The capability that cellular communications can provide will be adequate for the distribution network operation since it has advantages of low investment, fast implementation, and rapid setup of communications. While cellular communications is not ideal because operation-critical information is dependent on a public communication system, the benefits from the cellular option provides outweighs the other alternatives. Cellular networking has been widely used across the industry in the communications for Advanced Field Devices, including at PPL Electric.

Backhaul communications

Communications are needed to provide a secure, network to accommodate Rhode Island Energy's electric distribution system by providing high speed data transfer to and from the Distribution stations to the control center systems to provide SCADA and other real-time operational capabilities. The communication alternatives that could be considered for Backhaul include Public Cellular, Fiber or Plain Old Telephone Service (POTS) which refers to the traditional analog phone system that is implemented over physical twisted copper wire. The pros and cons are below along with the assumptions that have been included in this GMP.

Figure C.4: Backhaul Possible Communication Solutions and Assumptions

Technology	Pros (+) and Cons (-)	GMP Assumption
Public Cellular	- Availability - Secure / Resilient network - Bandwidth availability - Latency + Affordability - Scalability	
Fiber	+ Availability + Secure / Resilient network + Bandwidth availability + Affordability + Scalability	• Assumed fiber for backhaul communications • Near-term investments include the capital cost of fiber $23M for a shared transmission asset and $70M for the distribution fiber assets. • Fiber is deployed to all distribution stations by the end of 2028
POTS – Copper Wire	- - Availability - Secure / Resilient network - - Bandwidth availability -- Latency + Affordability - Scalability	

Bringing the fiber backhaul communications in-house improves security against cyber threats and resiliency by reducing reliance on external entities for communications support. Security, flexibility for data bandwidth capability, and speed are significant advantages of a company-owned fiber backhaul. A private fiber network allows the Company to better control the integrity of the network and the data exchanged with those devices.

Attachment D

ATTACHMENT D

System Issues Negatively Impacting DER Projects

System Impacts

Specific examples of instances where the Company would have been unable to maintain system reliability or safety due to DER projects are summarized below. Each example includes the issue encountered, the resulting reliability or safety impact, the methodologies deployed by the Company to resolve the reliability or safety issues, and the cost incurred by the Company to implement the solution.

- **Example 1**: During witness test of a 1,250 kW solar DG project, measurements of the primary system line to ground voltage exceeded 105%. Per Company requirements, DER restoration schemes are set to only reclose for voltages within +/-5% of nominal. In order to ensure auto-restoration would occur, system voltage needed to be reduced. Resolution: In order to reduce system voltage, a feeder capacitor was taken offline and seasonal settings were implemented to avoid high voltage during minimum loads. Estimated cost incurred by the Company for the setting changes was <$5,000.

- **Example 2**: During the analysis of a 216 kW solar DG project proposing to interconnect to a circuit served by the Clarkson Street Substation, it was determined that 3V0 was required but triggered prior to this proposed interconnection. Resolution: Leveraged existing 3V0 program to install required protection scheme at Clarkson Street substation. Estimated cost incurred by the Company for the Distribution Substation portion of 3V0 was $52,000.

- **Example 3**: During analysis of a 2,000 kW solar DG project proposing to interconnect to a circuit served by the Farnum Pike Substation, a pre-existing high voltage condition was identified at minimum feeder loads that would be exasperated with the interconnection of the DG. Resolution: System modification were implemented including replacing three capacitors with advanced controls, updating capacitor settings on two units, and changing station load tap changer settings. The Company was responsible for the costs associated with these specific modifications, because they were considered system improvements. Estimated cost incurred by the Company was in the range of $100,000.

- **Example 4**: Adverse impacts identified during analysis of a 9,750 kW photovoltaic solar project proposing to interconnect to a circuit served by the Hopkins Hill Substation, which was a subtransmission supplied distribution line. Issues included high voltage, excessive voltage fluctuation, and desensitizing of existing protective devices. Resolution: Methods proposed to resolve the issues include reducing project size by at least 64% (i.e., from 9,750 to 3,500 kW), reconductor about 8,500 feet of overhead conductor, upgrade line recloser with advanced controls, and install bi-directional regulator controls. The estimated cost for these system modifications are being developed as part of the System Impact Study.

DER Project Impacts

Although the Company does not formally track reasons behind DER project cancellation and project size (MW) reduction, Table 3.1 summarizes projects the Company recollects where the construction cost and timeline to integrate a DER resulted in negative economic impacts or significant project size decrease that resulted in a DER project cancellation or suspension.

Table D.1: Examples of DG Project Reductions due to High Interconnection Costs

Original Size / Decreased Size	Driver for Decrease	Comments
Cancelled Projects		
6,120 / 2,750 kW (55% reduction)	Overload	Engineering analysis identified potential conductor overloads with the interconnection of 6,120 kW. To accommodate the full 6,120 kW, substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 2,775 kW and about 12,000 feet of reconductoring was required to avoid the costly system upgrades. Customer was informed of required system modifications during the study and high-level costs of $1.4M to $1.8M for reconductoring were provided during early stages study. Option to decrease project size to 2,000 kW to avoid reconductoring was also presented.
10,000 / 3,150 kW (68% reduction)	Overload	Engineering analysis identified potential conductor overloads with the interconnection of 10,000 kW. To accommodate the full 10,000 kW, substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 3,150 kW and about 17,160 feet of reconductoring was required to avoid the costly system upgrades. Customer was informed of required system modifications during the study and high-level costs of $2.0M to $2.6M for reconductoring were provided. Option to decrease project size to 1,000 kW to avoid reconductoring was also presented.

6,720 / 2,200 kW (67% reduction)	Noncompliance with Voltage ANSI Range A/ Power Quality/ Overload/ Protection Concerns	Engineering analysis identified unacceptable voltage and fluctuation issues, equipment overloads, and saturation of equipment on the area electric power system. To accommodate the full 6,720 kW, substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 2,200 kW with the following system modifications was required to avoid the costly system upgrades: replace 900 kVar capacitor with advanced control unit, enable co-generation on circuit regulators, replace multiple reclosers with units integrated with advanced controls, install two new reclosers integrated with advanced controls, install zero sequence over voltage protection (3V0) on the substation transformer. Total estimates including cost to extend the area electric power system to the site were approximately $1.3M.
3,000 / 200 kW (93% reduction)	Protection Concerns	Engineering analysis identified the need for 3V0 protection on the station transformer with the interconnection of 3,000 kW. DG project size reduction to 200 kW was required to avoid the 3V0 upgrade.

Table D.2: Examples of DG Project Reductions due to High Interconnection Costs

Original Size / Decreased Size	Driver for Decrease	Comments
4,500 / 996kW (78% reduction)	Overload	Engineering analysis identified potential high voltage and conductor overloads caused by reverse power flow with the interconnection of 4,500 kW. Taking into account minimum circuit loading and prior DG applications, there was not enough hosting capacity on the feeder for a 4,500 kW project. To accommodate the full 4,500 kW, substantial modifications would be required. DG project size reduction to 996 kW was required to avoid the costly system upgrades. Customer was informed of required system modifications during the study and high-level costs estimates for required modifications. Option to decrease project size to 996 kW to avoid costly modifications was also presented.
Suspended Projects (Study Phase)		
4,500 / 750 kW (83% reduction)	Overload/ Noncompliance with Voltage ANSI Range A/ Protection Concerns	Engineering analysis identified potential high voltage, conductor overload, and protection issues with the interconnection of 4,500 kW. Major system modifications required to accommodate 4,500 kW included replacing station recloser and control with hardware capable of load encroachment schemes, changing existing protective device settings at multiple locations, installing approximately 15,000 feet of underground cable, and reconductor approximately 30,000 feet of overhead conductor. DG project size reduction to 750 kW was required to avoid the costly system upgrades.

6,360 / 2,180 kW (66% reduction)	Overload/ Noncompliance with Voltage ANSI Range A	Engineering analysis identified unacceptable voltage ranges on the area electric power system. To accommodate the full 6,360 kW substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 2,180 kW with the following system modifications was required to avoid the costly system upgrades: re-conductor approximately 8,500 feet of overhead conductor and replace existing 167 kVA line regulators with 333 kVA units integrated with advanced controls. Estimated cost for these system modifications were approximately $2M. Option to decrease project size to 1,040 kW to avoid reconductoring was also presented. Reduced estimate for system modifications were approximately $1M.

Attachment E

ATTACHMENT E

GMP Comparison: National Grid vs Rhode Island Energy

This Attachment highlights the similarities and differences between the National Grid GMP and the Rhode Island Energy GMP. Both plans created a grid modernization roadmap of technologies that are integrated to modernize the grid to achieve similar goals and objectives that aim for a delivery system that enables greater customer involvement and a clean energy future while providing safe and reliable electric service. This is in response to commonly held understanding in both Plans that DERs are creating planning and operational challenges where the underlying concern is a lack of visibility, situational awareness and system control that is necessary to operate a system becoming increasingly complex primarily due to DER integration and the shift to more reliance on intermittent generation coming from distributed supply.

Since the National Grid GMP preparation, more DERs have interconnected which enhances the relative current need for grid modernization capabilities in the Rhode Island Energy GMP. Deployment timing is a significant different between the two Plans, driven by present-day system complexity, declining reliability trend, and the fact that ADMS Basic is being made available by PPL through the Acquisition, which presents opportunity for near-term benefits that were not possible with the National Grid GMP. Rhode Island Energy's GMP roadmap calls for an accelerated grid modernization deployment (comparatively speaking), where Advanced Reclosers are used in conjunction with ADMS – FLISR to provide capability to improve deteriorating reliability trend on the Rhode Island Energy system. This investment and complimentary solutions identified as Foundational Investments provide operational capability for challenges today and for any DER adoption scenario in the future, including one that will achieve the Climate Mandate.

A summary of the similarities and differences between the Rhode Island Energy GMP and the National Grid GMP is summarized below:

Aspect	Similarities	Differences
Customer Enablement	AMF granular meter data is available to enhance GMP Utilize System Data Portal	- RIE – AMF fully available in 2026 - PPL Customer Portal available for RIE adoption
Advanced Field Devices	Advanced Reclosers, Capacitors, Regulators	- RIE did not apply feeder monitoring sensors - RIE concentrates deployment timing through 2028; National Grid deploys over 10 years. - RIE included Electromechanical relay upgrades - RIE uses NGRID VVO pilot results
Operational Systems and Applications	Use of ADMS with VVO, FLISR and DERMS applications Use of GIS IT Infrastructure	- RIE applies ADMS applications sooner - RIE has GIS available (National Grid developed and moved to PPL through TSA) - RIE leverages cyber assessment done by National Grid - RIE use of DER Monitor / Manage is unique
Communications	RF mesh for AMF	- RIE use of cellular for Advanced Field Devices; National Grid planned to build a private network for Advanced Field Devices. - RIE - use of RF Mesh for DER Monitor / Manage - RIE – Robust Fiber backhaul that is a shared Distribution / Transmission asset
Other		- National Grid included ITR; RIE did not - RIE used battery energy storage used as a GMP solution that is used to balance load and generation to minimize curtailment (requires utility control of asset)
Studies	Both used technical studies to determine avoided infrastructure using grid modernization alternative to meet the	- RIE – performed 8760 analyses through 2050 for all feeders defining avoided infrastructure upgrades in all Areas - National Grid used 6 sample feeders for analysis where results were extrapolated

	Climate Mandate	- RIE included expanded the National Grid scope to include bulk transmission in the analysis
Financial	Applied the Rhode Island PUC Docket 4600 Benefit Cost Analysis Framework	- RIE – more operational savings - RIE – has PPL subject matter expertise and actuals for a cost basis - RIE – utilized PPL reference standards - RIE used AESC 2021 report; National Grid utilizes 2018 report - RIE used 2% energy savings for VVO+.5% from AMF; National Grid used 3.5%.
Future Actions	TVR will be pursued in a subsequent docket	- RIE – uniquely committed to DER Monitor / Manage which will require additional approval(s) - TVR assumptions were based on Opt-in values for Whole House and EV but switched to Opt-out values by 2040

In conclusion, while there are many similarities, the GMP approach and ultimate proposal differs. Rhode Island Energy is calling for a "No Regrets" grid modernization approach with Foundational Investments that are useful now and for any DER adoption rate in the future. This compares to National Grid's 10-year deployment plan that is sequenced and deployed on a station-by-station basis. DER Monitor / Manage has been identified as a critical functionality which will be needed by Rhode Island Energy to help balance load and DG, and was not contemplated by National Grid. It has been included in the BCA, reduces the need for curtailment to maintain reliability and requires additional approval. Rhode Island Energy identifies the need and quantifies the benefit of a secure private Fiber network and included microprocessor relay upgrades in the distribution substations as a component of GMP due to the variability of loading conditions and two-way flow issues on the distribution system.

Attachment F

ATTACHMENT F

Distribution Study Results by Planning Area

This Attachment provides a visual version of the Distribution Study by Planning Area. The Distribution Study described in Section 5.0 summarizes the detailed planning analysis of 2030, 2040, and 2050. However, the GMP BCA was developed for a 20-year period, 2023 through 2042. The attached 2040 area graphs and tables are provided to illustrate the reliability issues and transmission and distribution infrastructure required by 2040 for both the No Grid Modernization alternative and the Grid Modernization alternative. With these transmission and distribution infrastructure investments, each alternative will mitigate criteria violations but at a much different level of required investment. A map of all Planning Areas in Rhode Island Energy is included as Figure F.1. This attachment includes feeder maps of criteria violations before and after including the Grid Modernization alternative for each Planning Area. It also shows the quantity of assets that would be needed in 2050 under the Grid Modernization alternative (GMA) and the No Grid Modernization alternative (NGMA). The infrastructure investment quantities required to solve violations in the NGMA and the GMA are provided by Planning Area.

The Distribution Study includes Battery Energy Storage Solutions (BESS) as a component of the GMA beginning in 2029. According to the Distribution Study, by 2030, there are 211 days that the system needs BESS at least an hour a day in the calendar year. BESS are used to fill in the valleys with demand and shave the peak. By 2050, the worst-case scenario shows that approximately 1200 MWh of BESS will be needed across the system. Of this need, 300 MWh is forecasted for deployment in 2029 and another 300 MWh is forecasted for 2030. This proposal does not suggest that Rhode Island Energy own BESS, but the Distribution Study area tables below identify the BESS needed by 2050 to maintain reliability. Because of market signals created by TVR, BESS is expected to evolve into commercially and consumer owned storage batteries, and vehicle to grid storage. The DER Monitor and Manage functionality will be required to operate the inverter-based resources including Solar PV and BESS.

Figure F.1 – Planning Areas

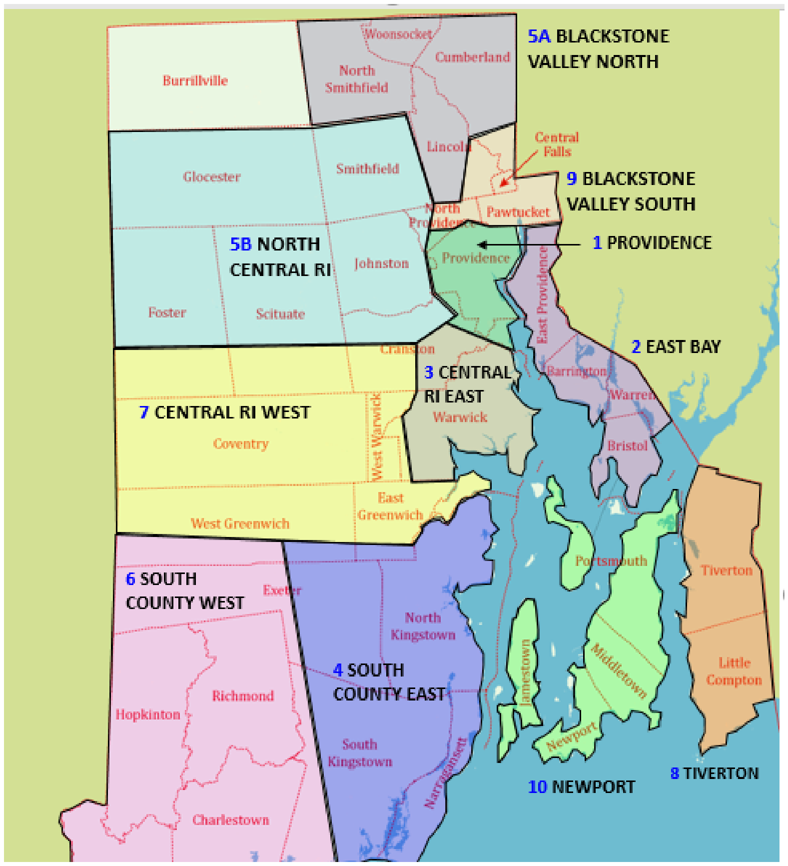


Figure F.2 - Legend

Figure F.3 – Blackstone Valley North – Issues

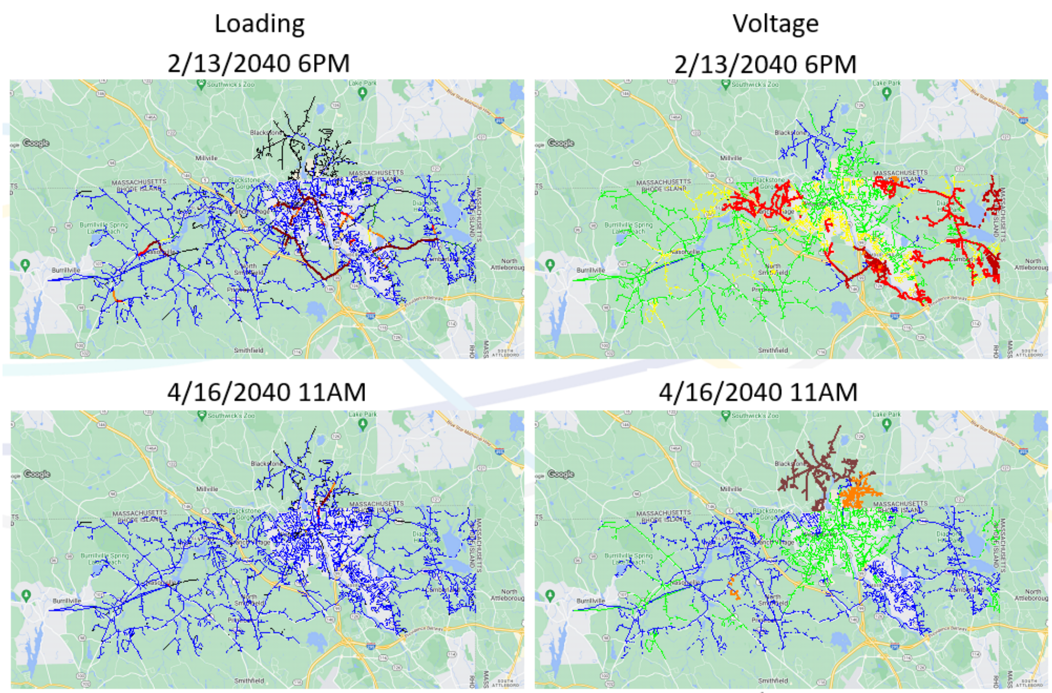


Figure F.4 – Blackstone Valley North – including Grid Modernization Alternative

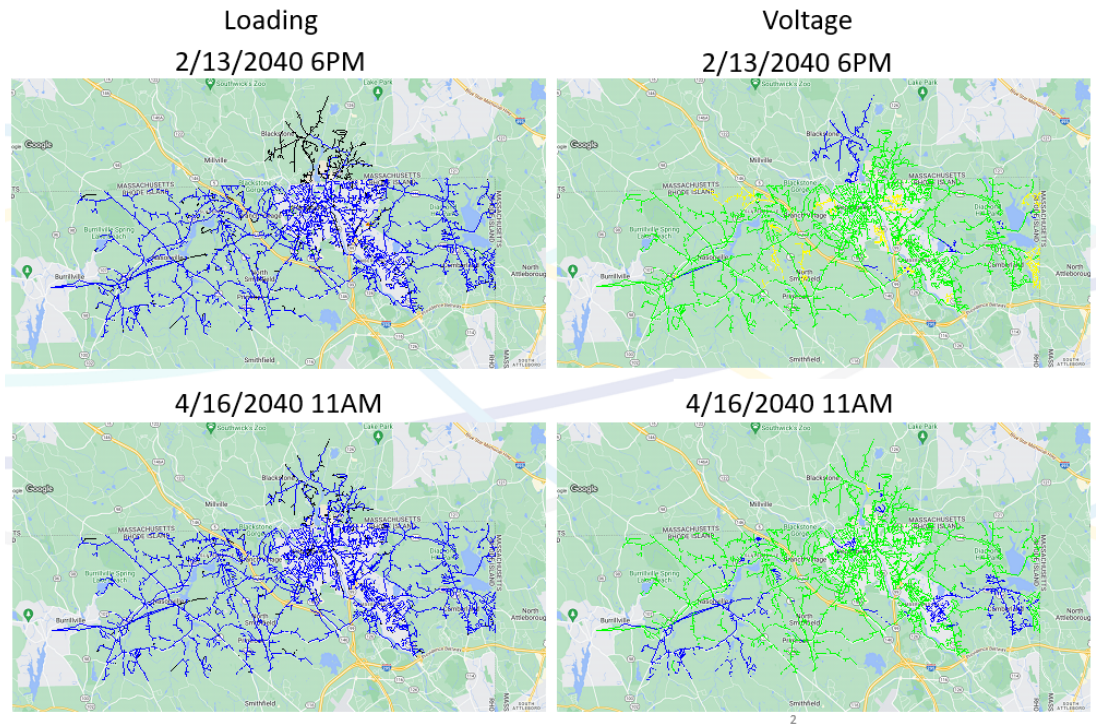


Figure F.5 Blackstone Valley North Comparison of Infrastructure

BVN Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	91	0
Capacitor	capacitors	40	8
Feeder - Existing - Lines	mi	9	10
Feeder - New - Lines	mi	14	29
Feeder - New - Sub	positions	6	15
Fuses	fuses	0	0
Reclosers	reclosers	130	5
Regulators - Line	regulators	6	3
Regulators - Sub	regulators	0	0
SubT - New - Lines	mi	6	12
SubT - New - Sub	positions	3	6
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	3	5
Transmission - New - Line	mi	0	2
Transmission - New - Sub	substation	1	2
		310	97

Figure F.6 – Blackstone Valley South – Issues

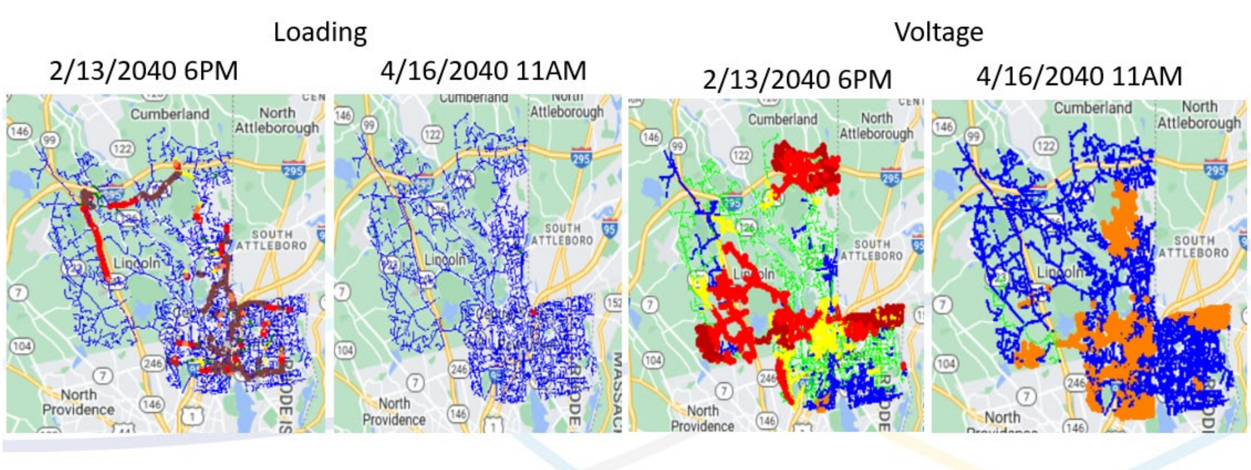


Figure F.7 – Blackstone Valley South – including Grid Modernization Alternative

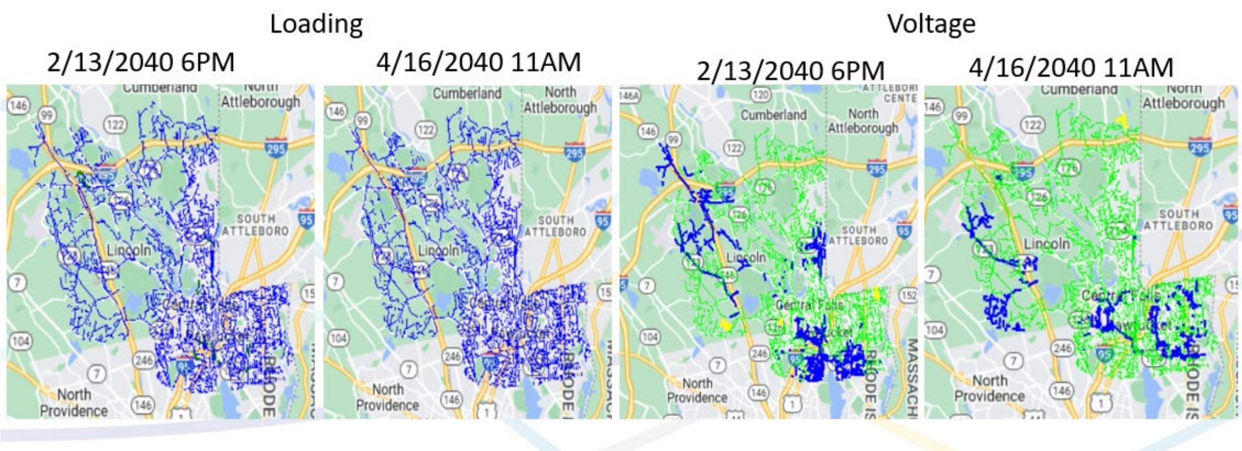


Figure F.8 – Blackstone Valley South Comparison of Infrastructure

BVS Infrastructure			
Type	Unit	Grid Modernization Alternative	No Grid Modernization Alternative
BESS	MWH	112	0
Capacitor	capacitors	51	11
Feeder - Existing - Lines	mi	11	12
Feeder - New - Lines	mi	17	35
Feeder - New - Sub	positions	12	30
Fuses	fuses	0	0
Reclosers	reclosers	130	5
Regulators - Line	regulators	6	3
Regulators - Sub	regulators	0	0
SubT - New - Lines	mi	7	14
SubT - New - Sub	positions	6	12
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	4	7
Transmission - New - Line	mi	0	3
Transmission - New - Sub	substation	1	2
		357	133

Figure F.9 – Central RI East – Issues

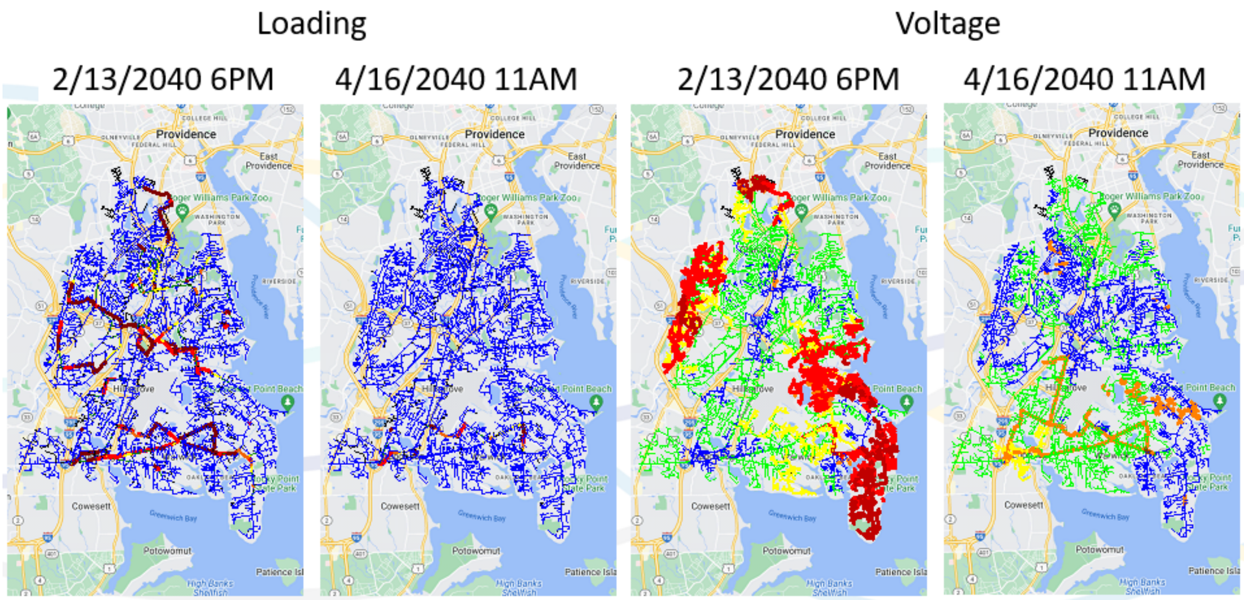


Figure F.10 – Central RI East – including Grid Modernization Alternative

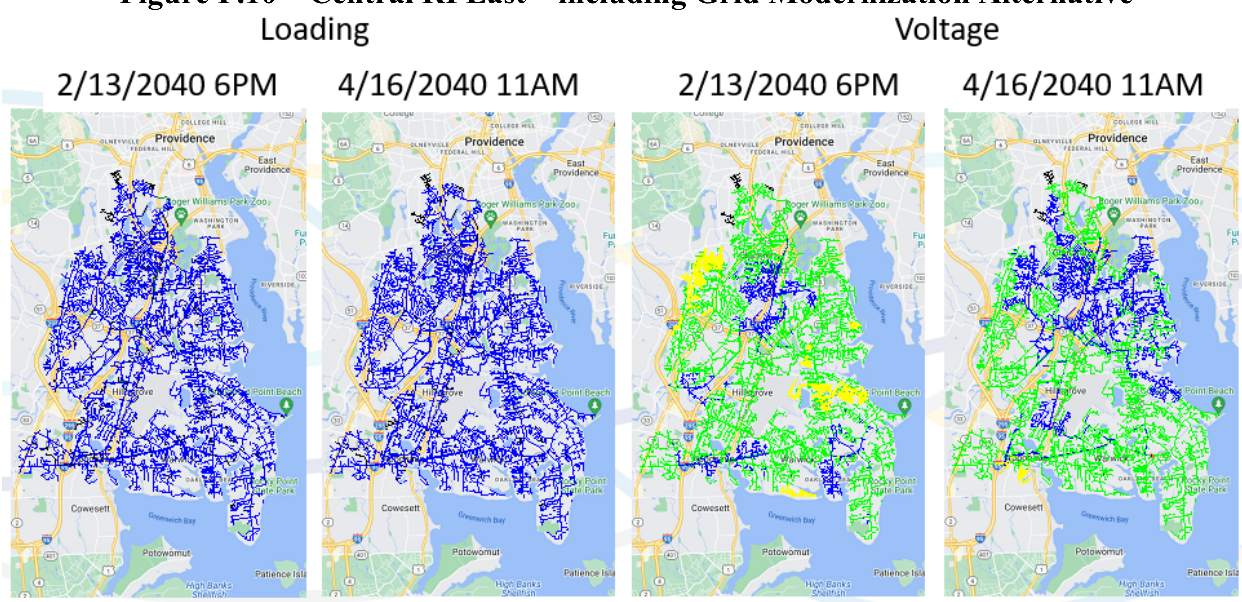


Figure F.11 Central RI East Comparison of Infrastructure

CRIE Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	134	0
Capacitor	capacitors	106	22
Feeder - Existing - Lines	mi	12	12
Feeder - New - Lines	mi	18	37
Feeder - New - Sub	positions	9	21
Fuses	fuses	0	0
Reclosers	reclosers	107	4
Regulators - Line	regulators	6	3
Regulators - Sub	regulators	0	0
SubT - New - Lines	mi	8	15
SubT - New - Sub	positions	4	8
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	4	8
Transmission - New - Line	mi	0	3
Transmission - New - Sub	substation	1	3
		409	136

Figure F.12 – Central RI West – Issues

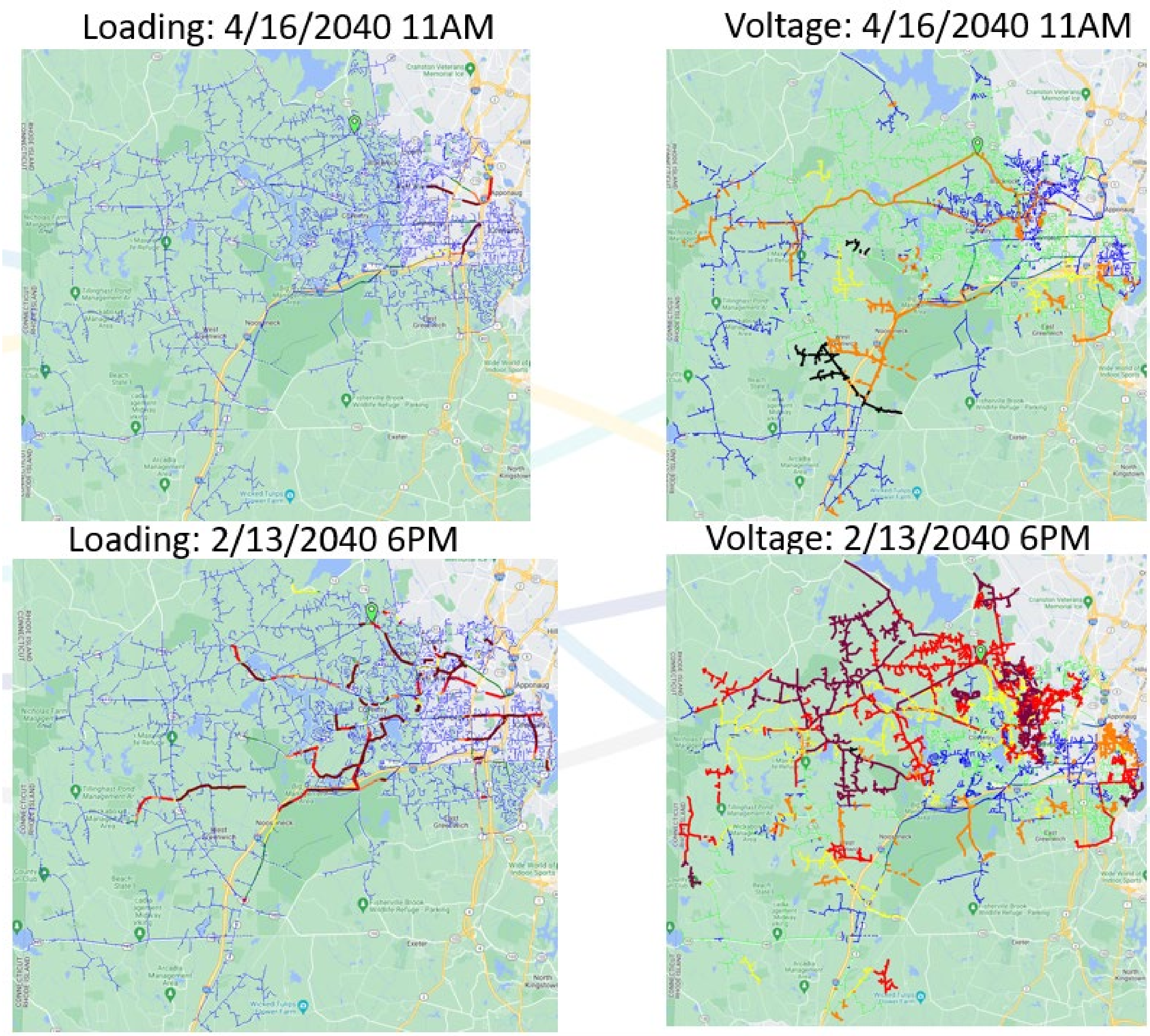


Figure F.13 – Central RI West – including Grid Modernization Alternative

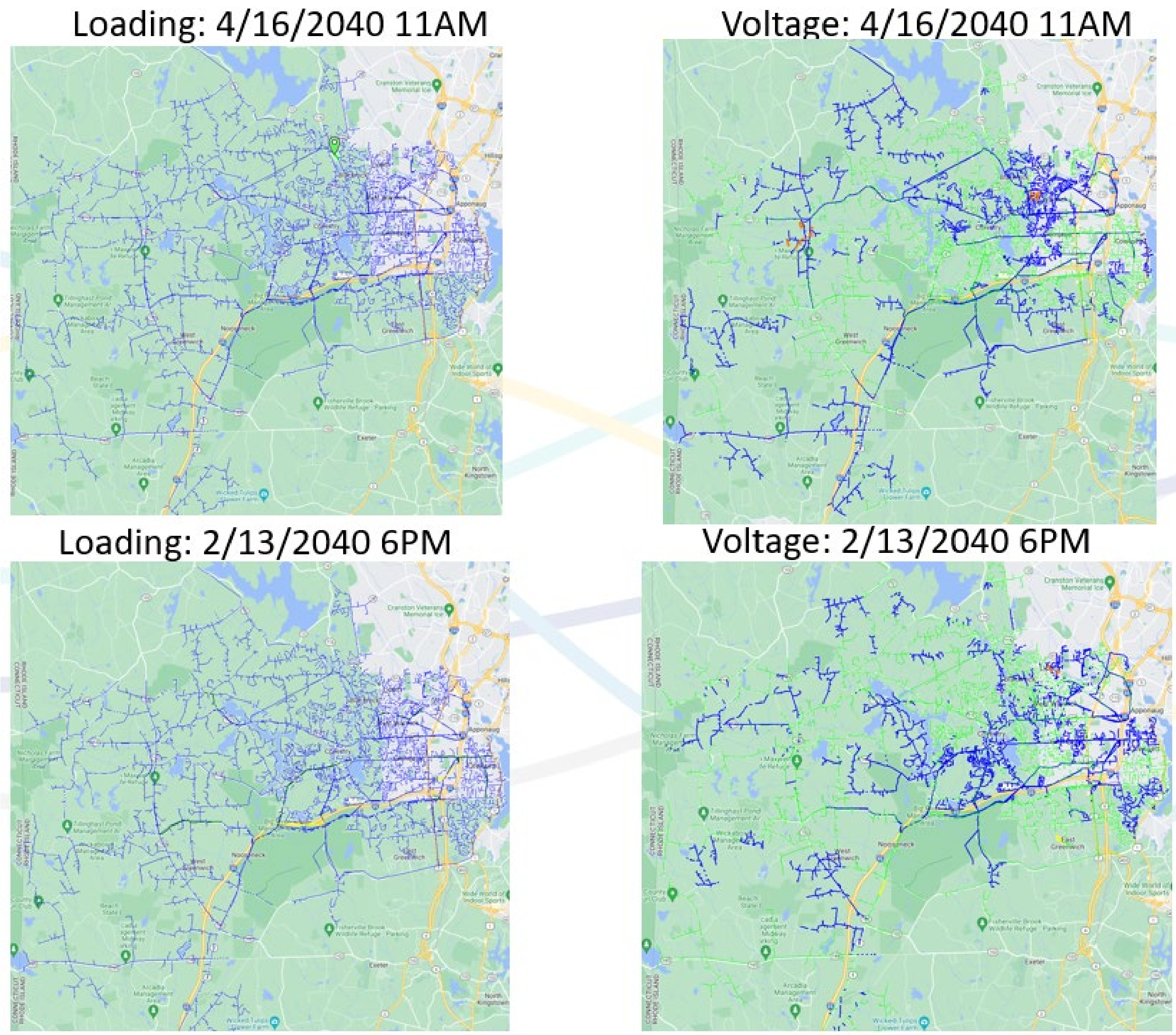


Figure F.14 – Central RI West Comparison of Infrastructure

CRIW Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	96	0
Capacitor	capacitors	76	17
Feeder - Existing - Lines	mi	17	17
Feeder - New - Lines	mi	13	40
Feeder - New - Sub	positions	9	17
Fuses	fuses	0	0
LTC - Existing - Sub	LTC	4	2
Reclosers	reclosers	188	0
Regulators - Line	regulators	3	0
Regulators - Sub	regulators	24	6
SubT - New - Lines	mi	21	15
SubT - New - Sub	positions	4	8
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	6	9
Transmission - New - Line	mi	0	12
Transmission - New - Sub	substation	1	3
		462	146

Figure F.15 – East Bay – Issues

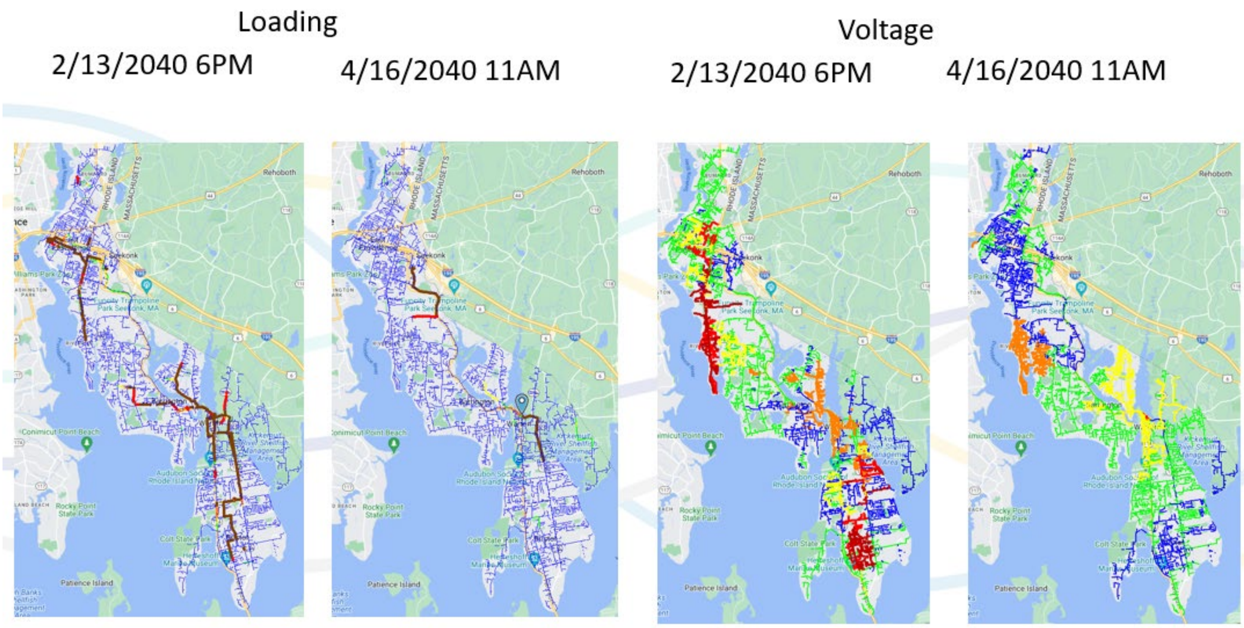


Figure F.16 – East Bay – including Grid Modernization Alternative

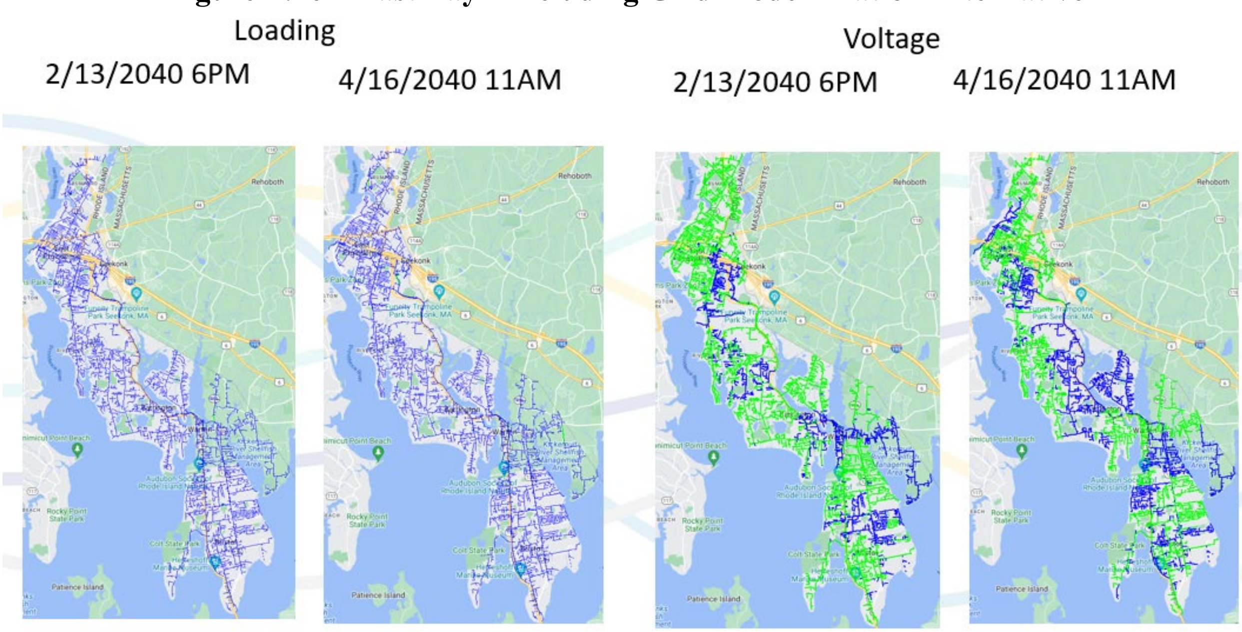


Figure F.17 East Bay Comparison of Infrastructure

EB Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	72	0
Capacitor	capacitors	101	4
Feeder - Existing - Lines	mi	17	7
Feeder - New - Lines	mi	3	7
Feeder - New - Sub	positions	4	11
Fuses	fuses	0	125
Reclosers	reclosers	162	5
Regulators - Line	regulators	0	0
Regulators - Sub	regulators	0	14
SubT - New - Lines	mi	0	0
SubT - New - Sub	positions	0	0
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	2	3
Transmission - New - Line	mi	0	5
Transmission - New - Sub	substation	0	2
		360	183

Figure F.18 – North Central RI – Issues

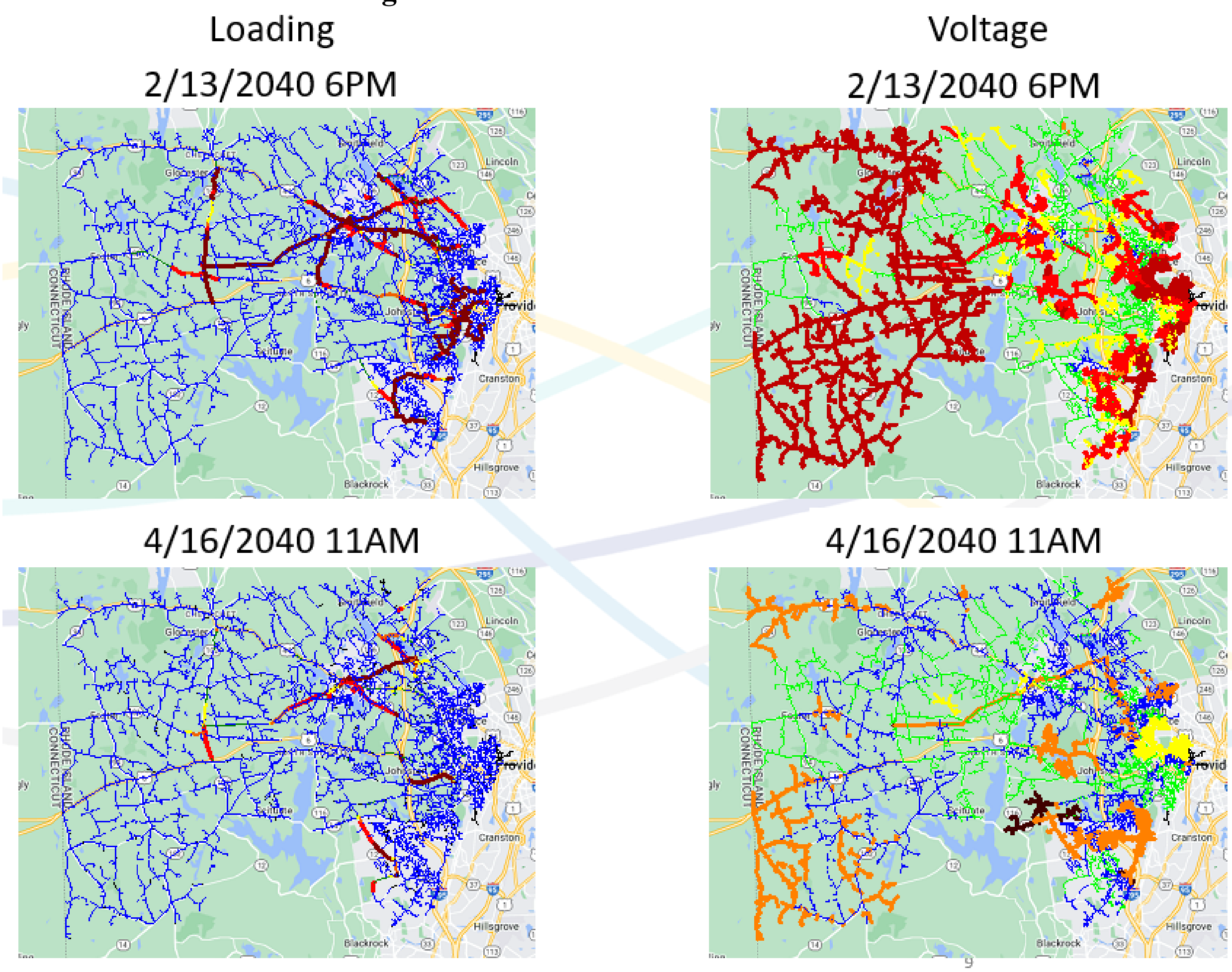


Figure F.19 – North Central RI – including Grid Modernization Alternative

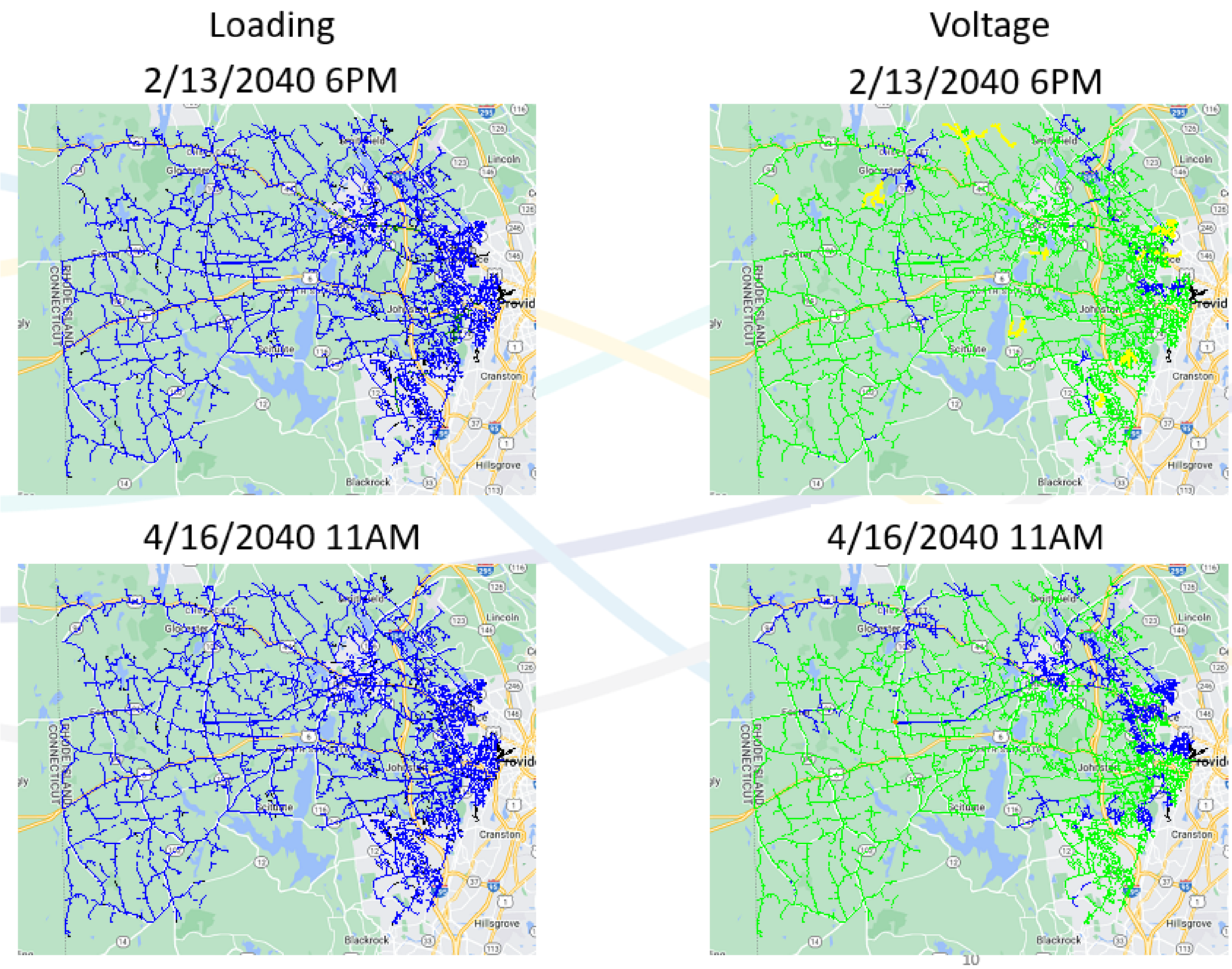


Figure F.20 North Central RI Comparison of Infrastructure

NCRI Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	49	0
Capacitor	capacitors	117	42
Feeder - Existing - Lines	mi	70	68
Feeder - New - Lines	mi	41	55
Feeder - New - Sub	positions	14	20
Fuses	fuses	0	0
LTC - Existing - Sub	LTC	0	0
Reclosers	reclosers	379	19
Regulators - Line	regulators	12	1
Regulators - Sub	regulators	40	14
SubT - New - Lines	mi	22	50
SubT - New - Sub	positions	4	9
Transformers - Existing - Sub	transformers	6	6
Transformers - New - Sub	transformers	1	4
Transmission - New - Line	mi	0	0
Transmission - New - Sub	substation	2	2
		757	290

Figure F.21 – Newport – Issues

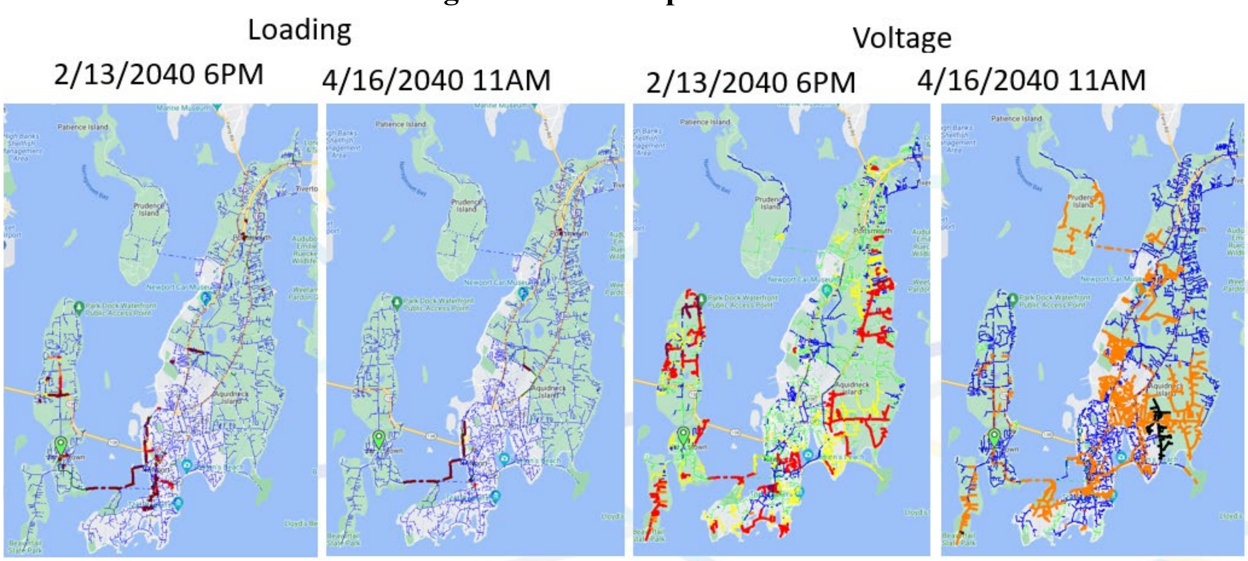


Figure F.22 – Newport – including Grid Modernization Alternative

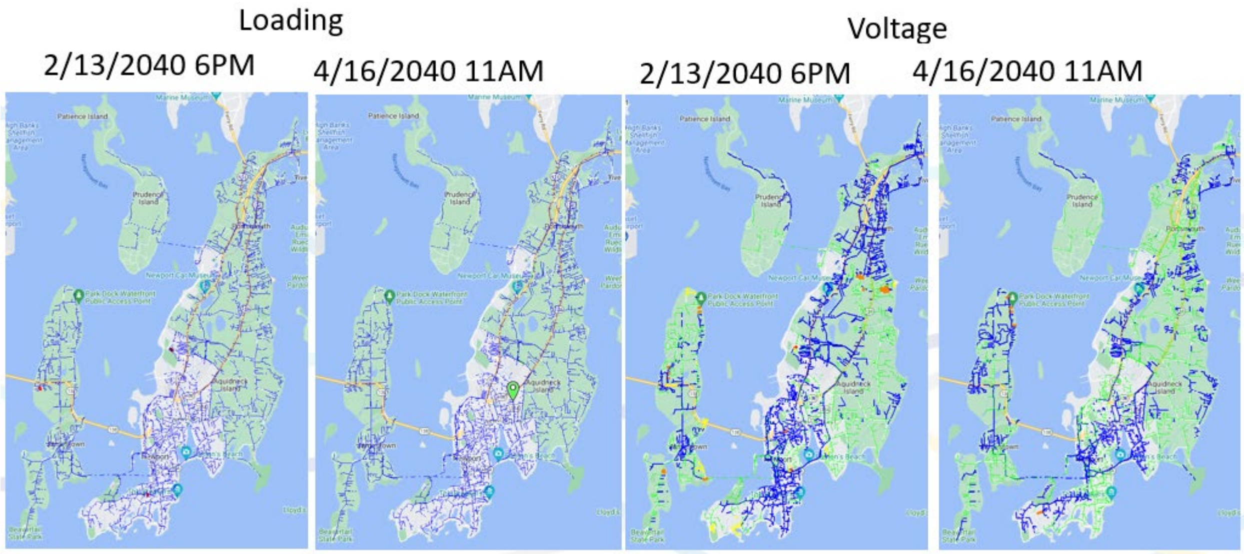


Figure F.23 Newport Comparison of Infrastructure

Newport Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	69	0
Capacitor	capacitors	65	14
Feeder - Existing - Lines	mi	13	13
Feeder - New - Lines	mi	19	40
Feeder - New - Sub	positions	10	23
Fuses	fuses	0	0
Reclosers	reclosers	53	2
Regulators - Line	regulators	6	3
Regulators - Sub	regulators	0	0
SubT - New - Lines	mi	8	16
SubT - New - Sub	positions	5	9
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	5	10
Transmission - New - Line	mi	0	3
Transmission - New - Sub	substation	1	3
		255	137

Figure F.24 – Providence – Issues

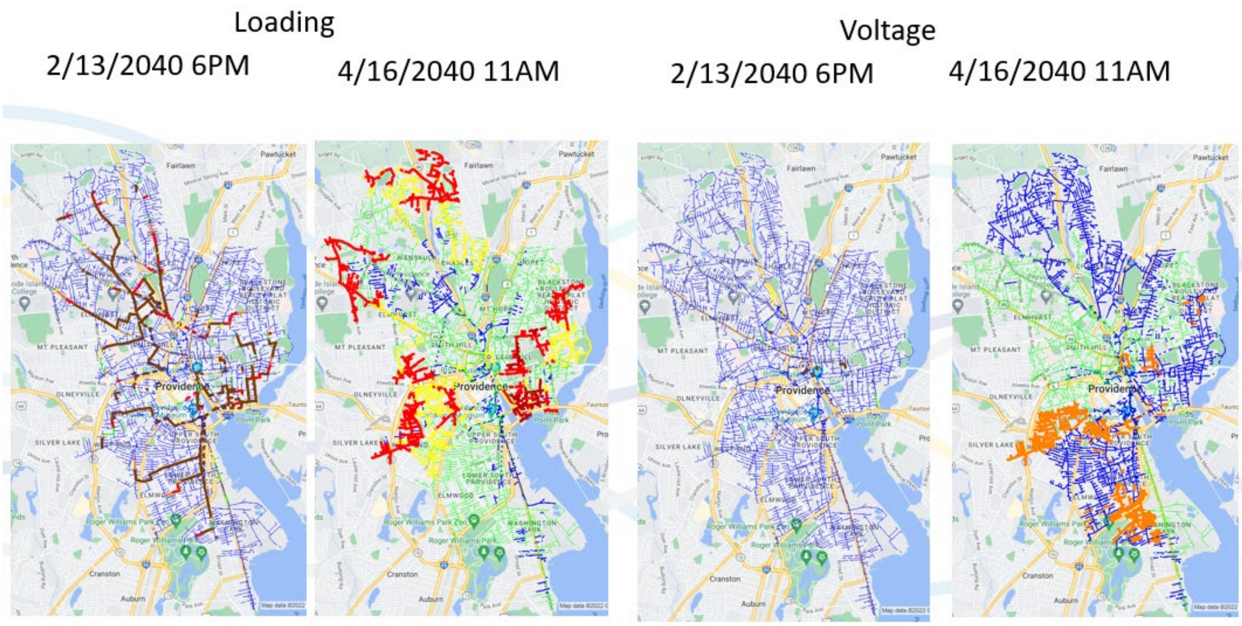


Figure F.25 – Providence – including Grid Modernization Alternative

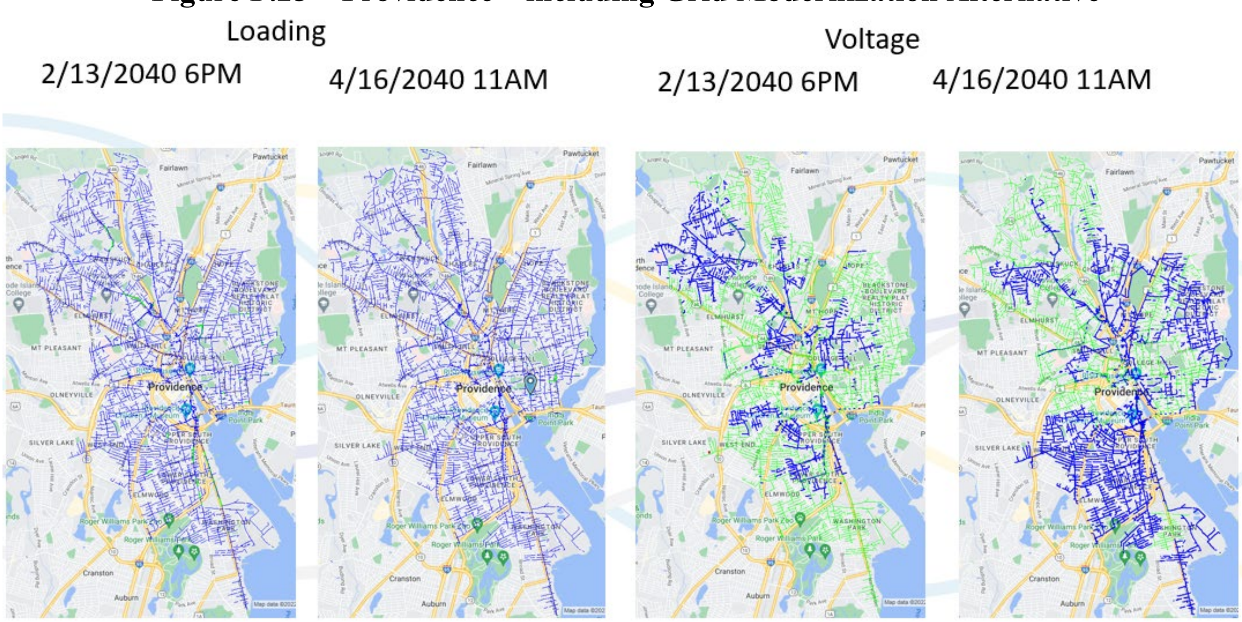


Figure F.26 Providence Comparison of Infrastructure

Providence Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	235	0
Capacitor	capacitors	133	28
Feeder - Existing - Lines	mi	13	14
Feeder - New - Lines	mi	20	41
Feeder - New - Sub	positions	21	52
Fuses	fuses	0	0
Reclosers	reclosers	92	3
Regulators - Line	regulators	6	3
Regulators - Sub	regulators	0	0
SubT - New - Lines	mi	8	16
SubT - New - Sub	positions	11	20
Transformers - Existing - Sub	transformers	0	0
Transformers - New - Sub	transformers	8	14
Transmission - New - Line	mi	0	3
Transmission - New - Sub	substation	2	4
		549	197

Figure F.27 – South County East – Issues

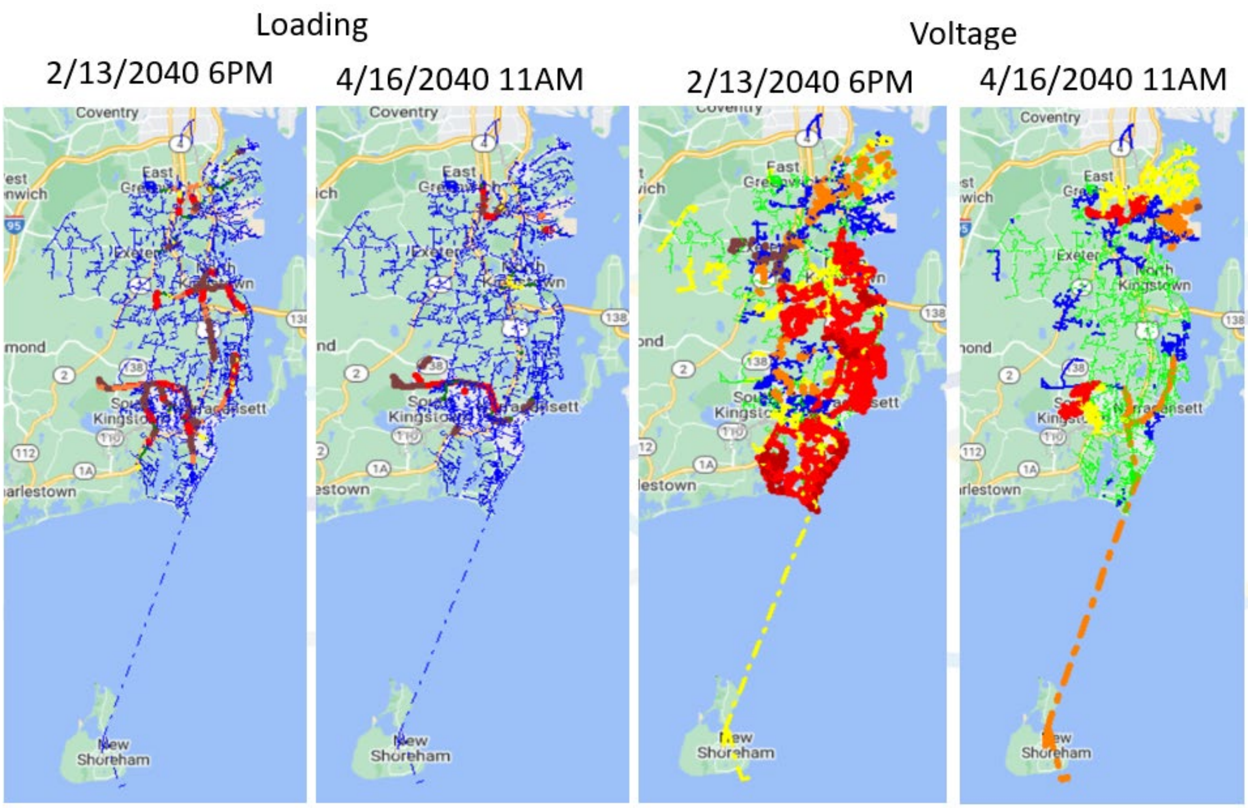

Loading
2/13/2040 6PM
4/16/2040 11AM
Voltage
2/13/2040 6PM
4/16/2040 11AM
Coventry
Exeter
North Kingstown
New Shoreham

Figure F.28 – South County East – including Grid Modernization Alternative

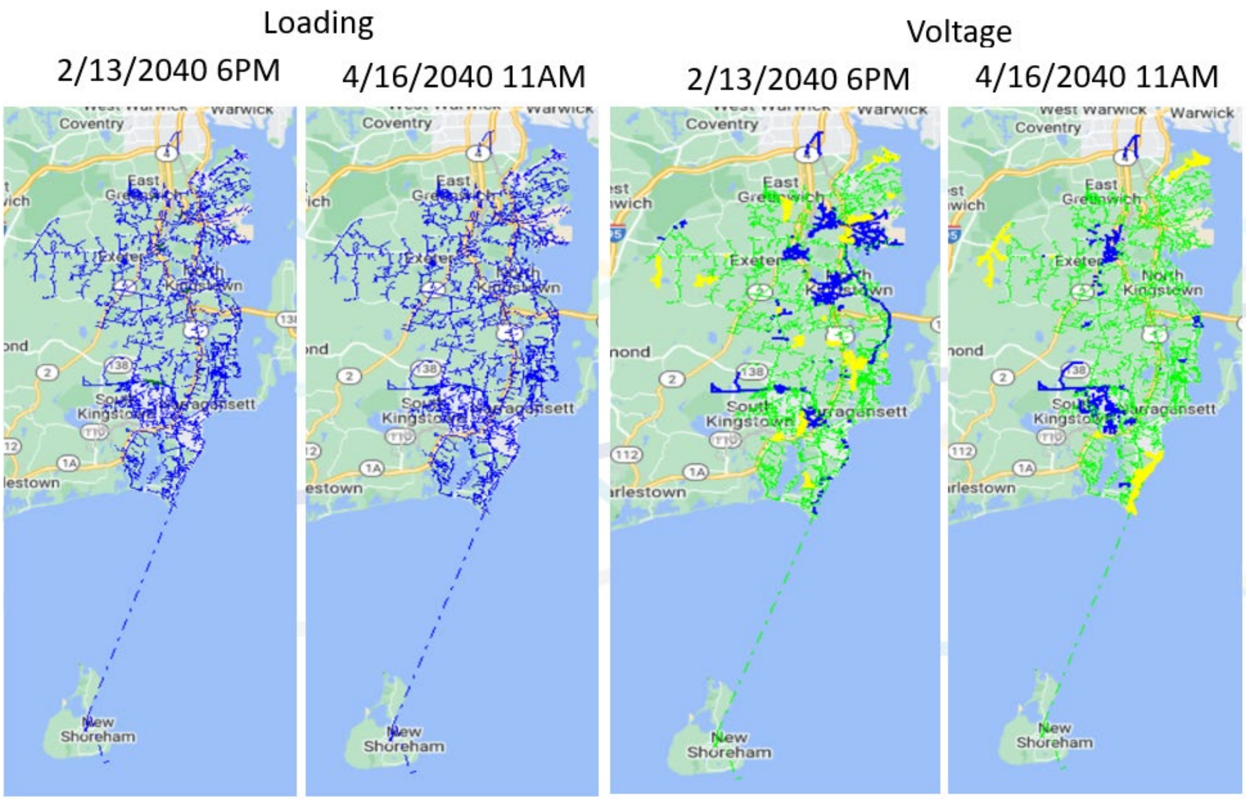


Figure F.29 South County East Comparison of Infrastructure

SCE Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	307	0
Capacitor	capacitors	41	12
Feeder - Existing - Lines	mi	20	43
Feeder - New - Lines	mi	0	31
Feeder - New - Sub	positions	0	13
Fuses	fuses	143	175
LTC - Existing - Sub	LTC	1	1
Reclosers	reclosers	197	13
Regulators - Line	regulators	6	6
Regulators - Sub	regulators	20	18
SubT - New - Lines	mi	4	27
SubT - New - Sub	positions	4	7
Transformers - Existing - Sub	transformers	1	0
Transformers - New - Sub	transformers	2	10
Transmission - New - Line	mi	0	0
Transmission - New - Sub	substation	1	3
		747	359

Figure F.30 – South County West – Issues

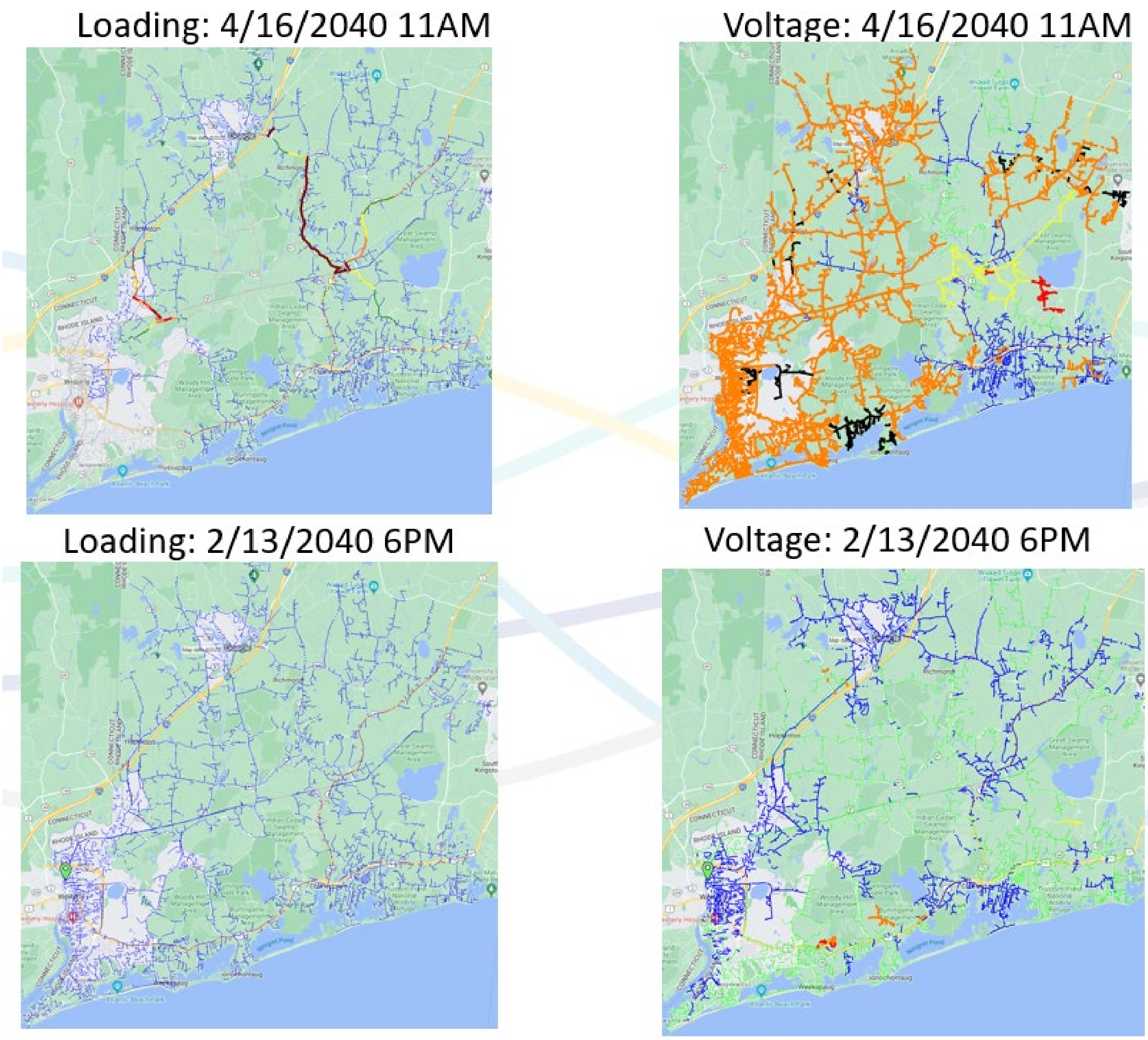


Figure F.31 – South County West – including Grid Modernization Alternative

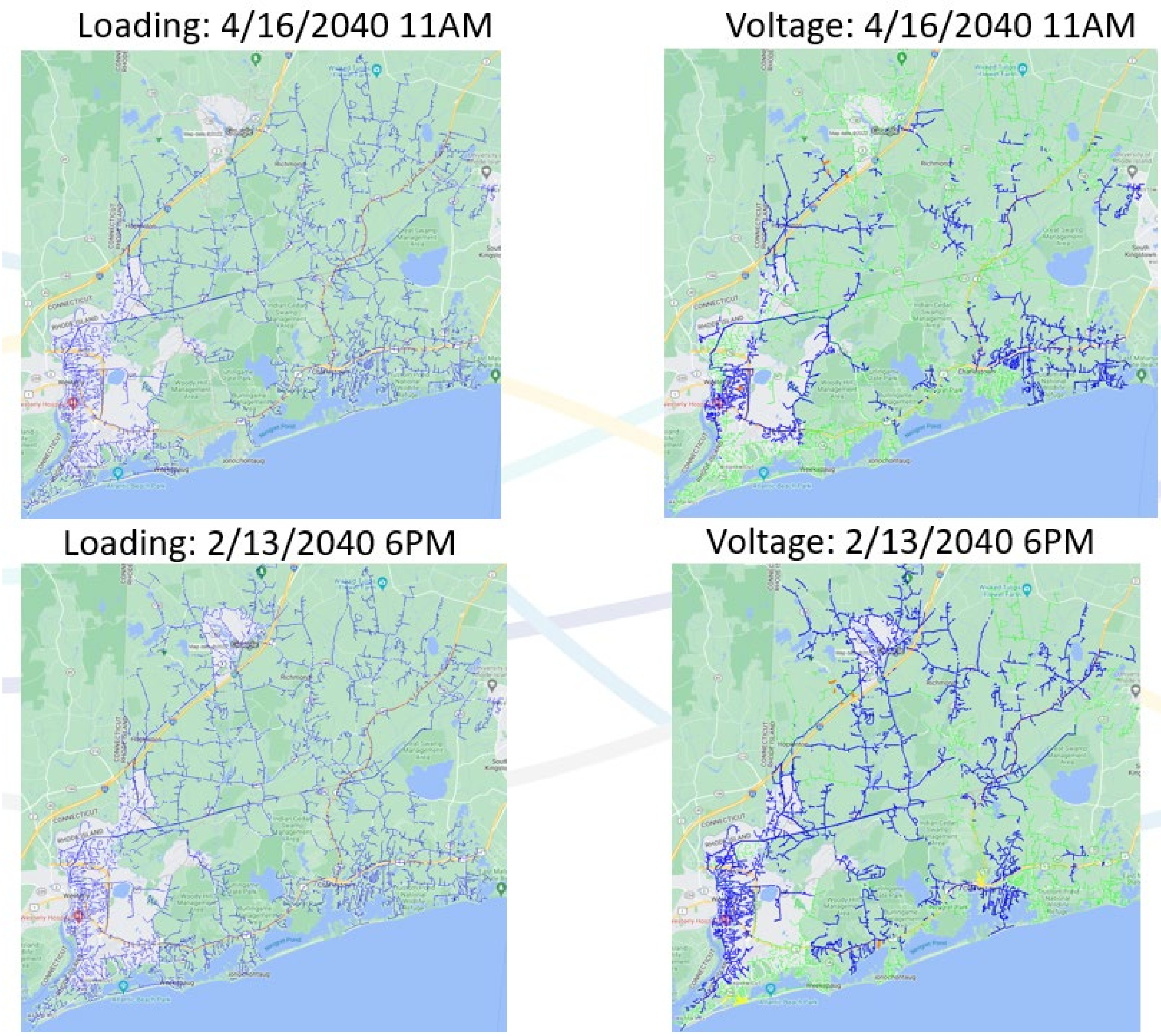


Figure F.32 South County West Comparison of Infrastructure

SCW Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	0	0
Capacitor	capacitors	67	3
Feeder - Existing - Lines	mi	3	3
Feeder - New - Lines	mi	0	16
Feeder - New - Sub	positions	0	4
Fuses	fuses	0	0
LTC - Existing - Sub	LTC	2	1
Reclosers	reclosers	89	0
Regulators - Line	regulators	0	0
Regulators - Sub	regulators	13	2
SubT - New - Lines	mi	2	2
SubT - New - Sub	positions	3	3
Transformers - Existing - Sub	transformers	1	2
Transformers - New - Sub	transformers	1	2
Transmission - New - Line	mi	0	0
Transmission - New - Sub	substation	1	1
		182	39

Figure F.33 – Tiverton – Issues

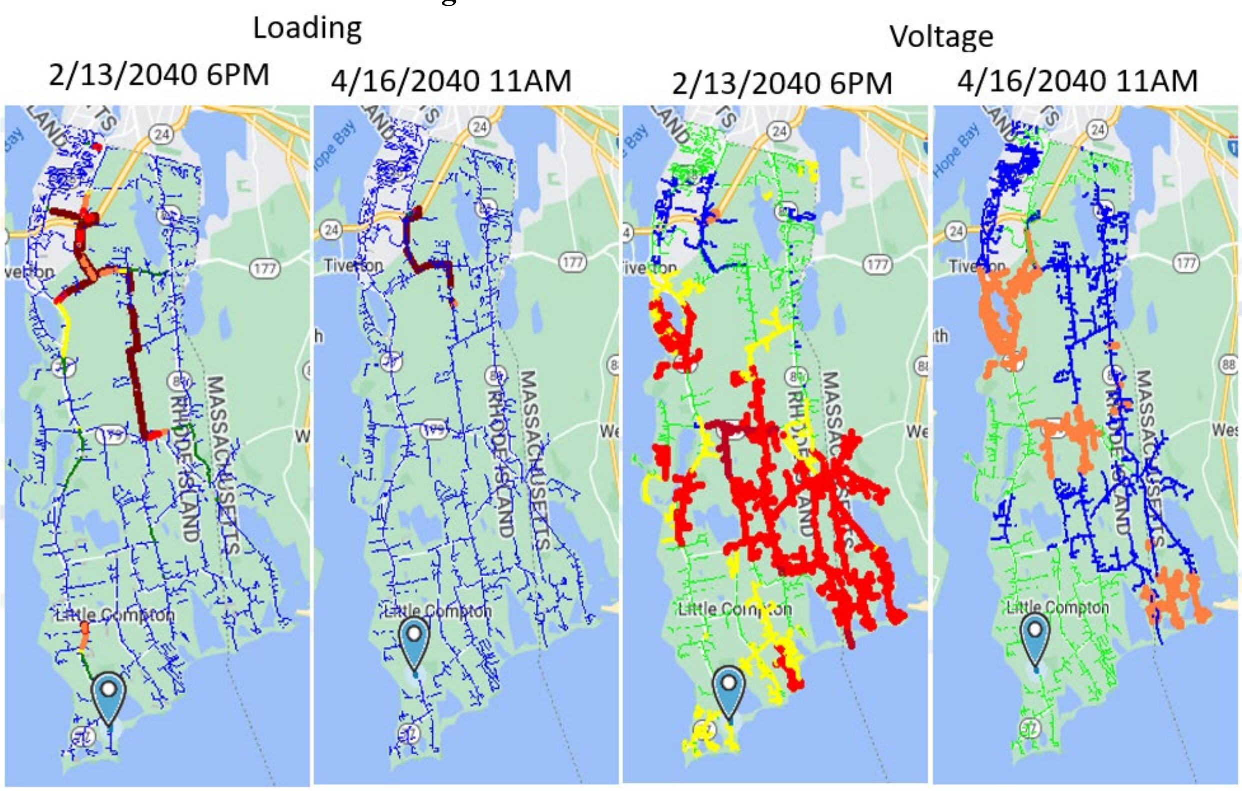


Figure F.34 – Tiverton – including Grid Modernization Alternative

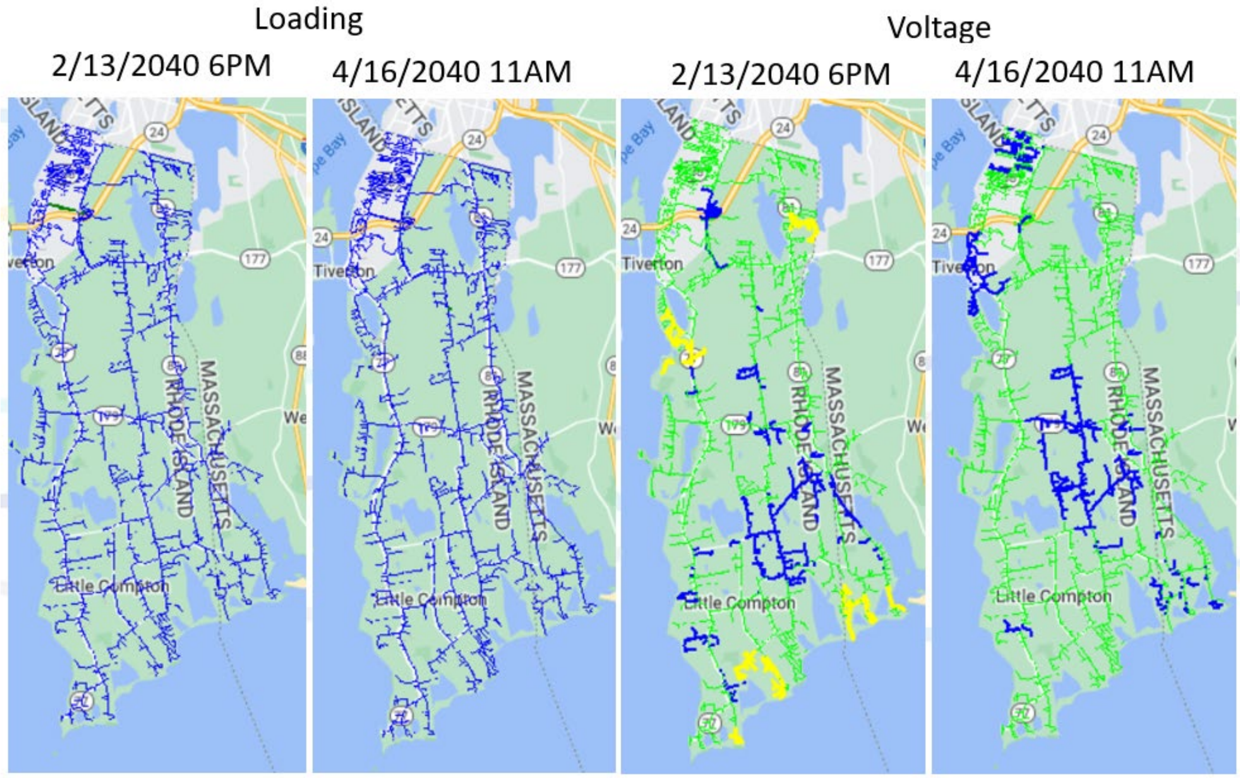


Figure F.35 Tiverton Comparison of Infrastructure

Tiverton Infrastructure			
Type	**Unit**	**Grid Modernization Alternative**	**No Grid Modernization Alternative**
BESS	MWH	50	0
Capacitor	capacitors	11	9
Feeder - Existing - Lines	mi	8	15
Feeder - New - Lines	mi	2	17
Feeder - New - Sub	positions	2	5
Fuses	fuses	33	63
Reclosers	reclosers	34	1
Regulators - Line	regulators	13	9
Regulators - Sub	regulators	2	5
SubT - New - Lines	mi	0	0
SubT - New - Sub	positions	0	0
Transformers - Existing - Sub	transformers	1	1
Transformers - New - Sub	transformers	0	1
Transmission - New - Line	mi	0	2
Transmission - New - Sub	substation	0	1
		156	129

ATTACHMENT G

DER Monitor/Manage Approach and Functionality

Overview

DER Monitor/Manage is a GMP Functionality that enables the visibility of DERs and the ability to manage them. This management ranges from ramping operations to full curtailment of an individual DER output if needed, for distribution safety or reliability purposes. Where DER are both visible and controllable, their operation can be managed to minimize negative impacts to the grid while optimizing the benefits to DER-owning customers and to other ratepayers. Visibility and controllability are prerequisites for fully *integrating* DER into the grid and is not available today at Rhode Island Energy.

Secure, cost-effective integration of DER is increasingly complex for several reasons:

- Distribution system operators may need to adjust the operations of DER frequently to help balance energy supply and demand, as evidenced by the GMP study (see Section 5).
- DERs come in wide range of types and sizes each with their own power characteristics and capabilities.
- DER is being deployed in large numbers, often interconnecting in concentrated locational pockets of the system with varying energy demand and supply. Adoption is accelerating.
- DER is owned and controlled by a range of entities, each with its own objectives and priorities, which may at times conflict with the goals of distribution system operator. For example, customers may want to reduce their bills and distribution system operators are most concerned about system reliability.

As the penetration of DER on a section of the grid increases, their impacts on grid operations—both positive and negative—will increase. Many operational and planning challenges emerge as DER penetration becomes increasingly significant part of the distribution system. These challenges include, but are not limited to, voltage swings, masked or hidden load, limited hosting capability, planning and operational uncertainties, and protection/operational challenges with multi-directional power flow. If not proactively addressed, increasing DER penetration will negatively impact system reliability.

Distribution system operators are ideally positioned to manage the increasingly complex DER ecosystem to optimize operation while maintaining the high degree of distribution system reliability that customers expect. Distribution system operators are ideal for the role because their primarily objective is grid reliability and with that, inherently having a comprehensive view of the grid, awareness of load profiles, grid configurations, locations of outages and line work, customer conditions, and much more. However, for distribution system operators to manage the increasingly complex DER ecosystem they need DER Monitor/Manage to provide necessary DER visibility, analysis and control that they do not have today.

DER Monitor/Manage Purpose

The purpose of Rhode Island Energy's DER Monitor/Manage Plan is to provide the Company with the necessary tools to operate its distribution system safely and reliably given the present and future DER interconnections that are anticipated to meet the state's Climate Mandate. Research conducted over the past decade points the way towards what is required to realize the full value of DER. EPRI has identified the following four levels of DER integration, in which DER becomes progressively more vital to grid operations[1]:

- *Level 1: The DER-Agnostic Grid -* DERs are relatively rare, small in size, and have negligible impact on the grid, and can therefore be ignored by the distribution system operator.

[1] "Maximizing Distributed Energy Resource Value Through Grid Modernization," EPRI (Aug 2021), http://mydocs.epri.com/docs/public/EPRI-Report-MaximizingDistributedEnergyResourceValue-20210804.pdf

- *Level 2: The DER-Aware Grid* - DERs are common and numerous enough that they have noticeable effects on grid operations and as a result need to be considered in planning and operations. To prevent adverse grid impacts of DER, the distribution system operator may manage DERs in basic ways, such as curtailing output of distributed solar systems to prevent grid voltage from fluctuating outside regulated limits. The distribution system operator accommodates DERs but does not maximize their value.

- *Level 3: The DER-Leveraging Grid* – DER visibility and control have increased to a point that the distribution system operator, aggregators, customers, and other entities can regularly use DER to provide various services to increase grid reliability, reduce emissions, or reduce operational costs. During summer when there is excess solar energy, the distribution system operator and aggregators may dispatch rooftop solar and storage systems to provide electricity to other parts of the grid where demand exceeds supply. The distribution system operator may also use DERs to address grid emergencies, generation outages, and other contingency events.

- *Level 4: The DER-Dependent Grid* – DER have been integrated into the grid to the degree that they have become mission-critical assets required for safe and reliable grid operations. Grid planning routinely uses DERs as non-wires solutions to defer investment in traditional grid infrastructure. During operations, the distribution system operator relies on DERs to maintain balance of generation and load, and to manage power flows to prevent outages, making DERs an essential part of the grid.

Some of the areas within Rhode Island Energy's service already have exhausted the available hosting capacity due to extensive DER penetration. However, the Company generally lacks the visibility to be aware of DER operations and impacts on the distribution system on any given day. Except for a few large interconnections, distribution system operators lack the ability to have visibility and manage DERs to fully integrate DERs with the distribution system: DER Monitor/Manage will provide this capability to reach Level 4 integration of DER as described above.

IEEE 1547-2018 Standard Presents DER Opportunity

In response to increasing DER penetration, the Institute of Electrical and Electronics Engineers ("IEEE") revised Standard 1547 in 2018 ("IEEE 1547-2018"), which defines requirements for DER smart inverters to support the distribution system.[2] When these smart inverters are coupled with DER management devices, electric utilities can monitor and manage DERs interconnected with their distribution systems. IEEE 1547-2018 outlines requirements concerning the interconnection and interoperability performance of DERs, including operation, testing, safety, maintenance, security requirements and grid support functions.

The IEEE 1547 has been the de-facto standard for DER interconnections in the United States since it was originally published in 2003. Since then, technology and economic advances have elevated the DER penetration, resulting in a continual evolution of IEEE 1547. In April 2018, IEEE Standard 1547 was revised to standardize inverter capability requirements, identify communication interface standards, require expanded grid support functions such as requiring the capability to actively regulate voltage, ride through abnormal voltage/frequency conditions, and provide frequency response and improved anti-islanding protections.

Of specific importance to Rhode Island Energy and DER customers is the new requirement for DER inverters to be "smart," i.e., capable of providing grid support functionality and that DERs must provide the local electric distribution utility with a standardized local interface for the

[2] "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," in *IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003)*, vol., no., pp.1-138, 6 April 2018, doi: 10.1109/IEEESTD.2018.8332112.

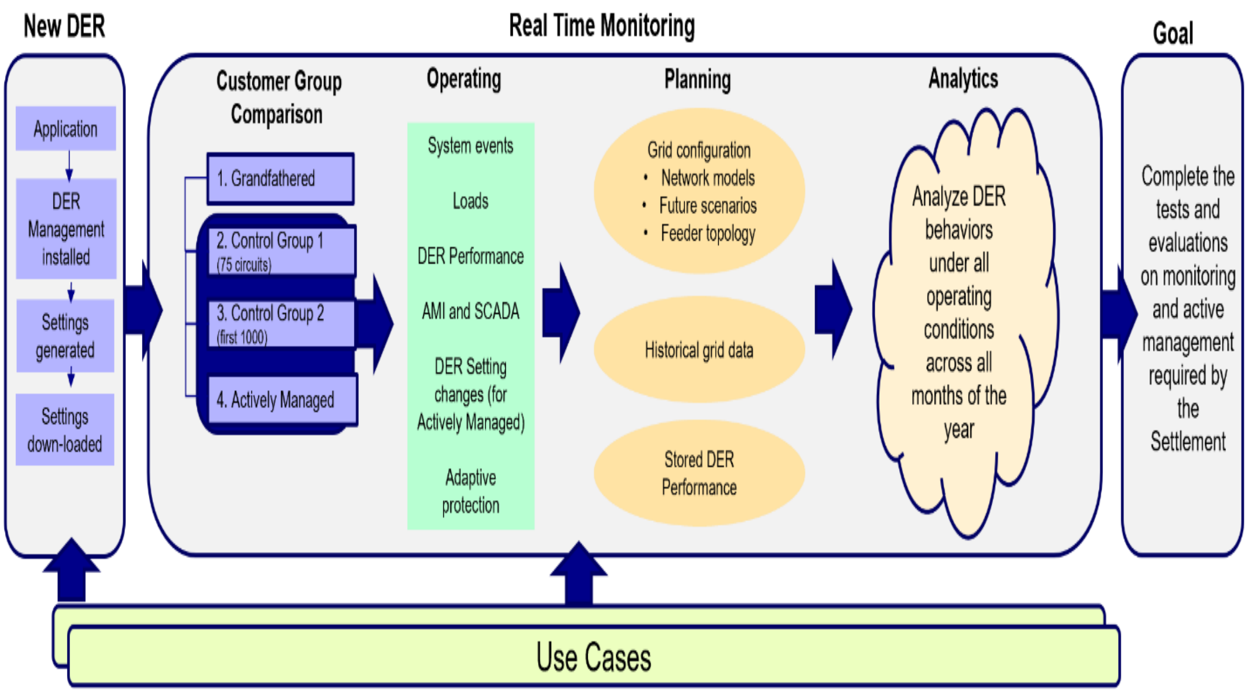
monitoring and management of the DER. Section 10.2 of IEEE 1547- 13 2018 specifies that DERs "shall use a unified information model, and non-proprietary protocol encodings based on international standards or open industry specifications as described in 10.7." Section 10.7 then specifies that the DER must offer either an Ethernet 16 or a Serial (RS-485) interface that uses one of three standardized protocols: (1) SunSpec Modbus; (2) DNP3 (IEEE 1815); or (3) SEP2 (IEEE 2030.5). The more sophisticated and standardized communications specified by IEEE 1547-2018 will enable DERs to convey performance data, so the Company will have increased situational awareness and can more quickly diagnose and address any operational or maintenance issues.

IEEE 1547-2018 has addressed a significant and longstanding impediment to the development of replicable and scalable DER management which is inverter protocol standardization. Standardized information models detailing read/write protocols and the availability of a standardized local interface that is accessible for utilities enable scalable interface with DERs instead of creating custom programs for each inverter type. This is a significant breakthrough for true integration and harmonization of DER with the grid because it presents opportunity for interoperability of DERs with grid operations. Having an interoperable system and embedding interoperability as a foundational component of the electricity system as it evolves, will ensure that all will be able to participate and benefit from this evolution. Reliance on standards, specifically open standards with well-developed testing and certification programs, are vital to the success of this evolution.

PPL Electric Experience

In December 2020, PPL Electric received approval from the Pennsylvania Public Utility Commission to require smart inverters that meet the new IEEE and UL standards, to install DER management devices on new DERs interconnected with its distribution system, and to monitor and manage those new DERs. PPL Electric is in the process of testing and evaluating costs and benefits of monitoring and actively managing newly interconnected inverter-based DERs across its system. The evaluation now includes approximately 2,900 DERs, with 1,560 in the "Actively Managed" group (or about 18.3 MW), using an evaluation approach shown in Figure G.1.

Figure G.1: PPL Electric DER Management Evaluation Approach



Rhode Island Energy will build upon PPL Electric's experiences and lessons in its DER monitoring and management planning effort. Cost estimates and assumptions used in this GMP for DER Monitor/Manage were informed by the PPL Electric experiences.

DER Monitor/Manage enables DER Grid Services

The grid can support more DER when it is equipped with the appropriate monitoring and management infrastructure, and the DER will be able to provide benefits to grid operations. Many types of benefits or "grid services" are possible. For example, numerous customer-sited energy storage systems acting in concert could dispatch power to serve local loads. This can reduce overall load and decreasing the amount of power flowing through the delivery system, which can be valuable in reducing congestion during certain times of day.

Potential grid services from DER include[3]:

- **Load leveling:** Smoothing load by absorbing energy from or injecting energy into the grid.
- **Peak demand reduction:** Providing power to the grid to limit the peak load on grid assets.
- **Ramping support**: Providing supplemental power when solar or wind generation output fluctuates.
- **Energy arbitrage:** Shifting energy production from low value to high-value periods.
- **Distribution capacity:** Injecting power (rooftop solar, EVs, and storage) or reducing consumption (EVs, appliances, and other controllable loads) to reduce net load on specific distribution infrastructure.
- **Firm capacity:** Guaranteeing availability of backup capacity to compensate for dips in renewable energy production.
- **Reserves:** Grid-connected reserve power ready for instantaneous delivery as well as reserves not connected to the grid but able to delivery power within minutes.
- **Black start:** Bringing a generation plant from shutdown to a specified power level within a specified time, without support from transmission lines.
- **Frequency regulation:** Providing short-term power adjustments to help maintain grid frequency within required levels.
- **Voltage support:** Producing or absorbing reactive power to maintain grid voltage within required levels or to correct voltage excursions.
- **Back-tie:** Supplying power or decreasing consumption to reduce loading of grid infrastructure when distribution system operators reconfigure distribution feeders during an outage recovery.

[3] "Maximizing Distributed Energy Resource Value Through Grid Modernization," EPRI (Aug 2021), http://mydocs.epri.com/docs/public/EPRI-Report-MaximizingDistributedEnergyResourceValue-20210804.pdf

- **Renewable self-consumption:** Using a behind-the-meter energy storage system to absorb power from a rooftop solar system to avoid curtailment of excess generation.

Providing a grid service can sometimes have simultaneous positive and negative grid impacts. For example, when DER export power to the grid to alleviate congestion, the additional energy may cause the grid voltage level to fluctuate above or below regulated requirements. This illustrates how DER grid services may create more operational challenges than they solve if there is not proper orchestration by the distribution system operator. DER services must be dispatched in a way that balances preferences of DER owners while supporting the needs of the distribution grid.

DER Monitor/Manage is Strategically Essential

DER Monitor/Manage is strategically important to successfully achieving goals and objectives for the GMP. In the Distribution Study discussed in Section 5, the "Reference Case" without Grid Modernization investments assumes the Company will need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the design limitations of the system. This would result in an average renewable DG seasonable curtailment of 17% of its annual energy output in 2030 in order to operate the system within limits. However, the alternative with Grid Modernization used in the Distribution Study assumed DER Monitor/Manage would reduce DER curtailment requirements from approximately 17% to 1% per year. In doing so, DERs would likely be ramped down, rather than completely curtailed using DER Monitor/Manage capability. This approach would maximize renewable energy production, optimize the use of T/D infrastructure, avoid new infrastructure spend, improve the customer experience, improves power quality, and increases hosting capacity.

The Distribution Study alternative with Grid Modernization also specified the need for 600 MWh of energy storage by 2030 that grows to 1215 MWh by 2050. The ownership of the energy storage is not specified in the GMP; however, it does need to be under the control of the Company to achieve the load balancing objective and maintain reliability. DER Monitor/Manage will provide the necessary functionality to control the energy storage in order to satisfy the study requirements.

In addition to providing these core capabilities to achieve the GMP load balancing and stability objectives, DER Monitor/Manage promises a wide range of additional operational benefits in the areas of safety, power quality, efficiency, and reliability while facilitating the increased deployment of DERs through the service territory. Below are further explanations of these benefits:

- By enabling Rhode Island Energy to monitor and manage the DERs, the amount of DERs that can be safely and reliably interconnected with the distribution system can be significantly increased, as demonstrated in various industry research studies. [4] Power factor management can increase the hosting capacity of the Company's electric distribution system, meaning that the Company can interconnect more DERs without the need for system upgrades. Currently, DER nameplate ratings are used to determine hosting capacity and, if required, determine system upgrades. With visibility of the DERs' actual output, using the Company's DER Monitor/Manage Plan, planning efforts will be more precise which will increase of hosting capacity and result in more accurate assessments for system upgrades which will allow more interconnections without triggering additional capital investments.

- Safety benefits will result from distribution system operators being able to better determine the output of impacted DERs during a disturbance or an outage on the system and enable

[4] See Seuss, J., et al., "Improving Distribution Network PV Hosting Capacity via Smart Inverter Reactive Power Support" (July 2015), available at https://energy.sandia.gov/download/33230/; Ding, F., et al., "Technologies to Increase PV Hosting Capacity in Distribution Feeders" (July 2016), available at https://www.nrel.gov/docs/fy16osti/65995.pdf

distribution system operators to safely perform system restoration without violating any equipment constraints and improve reliability. If necessary, the Company could remotely curtail the DERs in the area where employees are maintaining or repairing de-energized lines. Depending on the characteristics of the circuit, a delay or failure to trip off could lead to unintentional islanding of the DER. This unintentional islanding occurs when the generation from the DERs is strong enough to supply the load when isolated from the distribution system. If crews are dispatched to repair equipment and see a visible break in the Company's protective equipment, they cannot assume the downstream line is de-energized. With an unintentional island, the lines will be energized downstream of this device, which can be a safety hazard. If there are downed conductors, the DER can backfeed into this low impedance fault and can cause fires or electrical hazards. Also, when unintentional islanding occurs, there is no way for the Company to maintain power quality, which can lead to customers' equipment being damaged. Currently, Rhode Island Energy has no way of detecting if an unintentional island forms or de-energizing DERs to remove the island. DER Monitor/Manage would enable Rhode Island Energy to locate and disconnect DERs in these unintentional islanding scenarios.

- Power quality can be improved at customer sites by leveraging DER voltage support functions, potentially avoiding the need to deploy traditional voltage regulation infrastructure. Power factor, Volt/VAR, Volt/Watt, ramp rates[5], and reactive power functions allow DERs to maintain appropriate voltage levels on the distribution system. DER Monitor/Manage will also be coordinated with the Volt/VAR optimization to enhance efficiencies and provide the ability for fine tuning reactive control capability. As a result,

[5] Inverters can change the rate at which the generation output ramps up to full capacity when the solar irradiance becomes present. The default setting for this parameter is 100%, which means when clouds give way to sunshine, the inverter ramps from almost no output to the full amount allowed by the solar resource. Given the intermittent nature of solar irradiance, inverters ramping up quickly can lead to power quality issues in high penetration scenarios, such as flicker or spikes in voltage

the Company will be able to reduce DER interconnection system upgrade costs and reduce the need to deploy equipment, such as voltage regulators, to manage voltage irregularities. Similarly, frequency/watt functionality allows a DER to maintain appropriate grid frequency thereby improving the stability of the distribution system and the DER's ability to maintain a connection with the distribution system.

- The stability and reliability of the system will be improved using smart inverters with IEEE 1547-2018 capabilities, DERs will have the ability to "ride through" low and high voltage and frequency events. As a result, DERs will be more likely to remain online and operate properly during abnormal voltage and frequency disturbances occurring on the distribution system, thereby maintaining reliable service. Inverters without a setting for this functionality traditionally "trip off" DERs when a system disturbance occurs. In higher solar PV penetration scenarios, large numbers of inverters going offline due to a deviation from normal distribution system operating parameters can exacerbate the stress on existing infrastructure and negatively affect service reliability. Keeping DERs online during short-term system interruptions can mitigate system imbalances between load and generation resources and can reduce the likelihood of more significant disturbances to the system. Also, when a large number of DERs trip offline at the same time, they can destabilize the electric system and increase the likelihood of a cascading outage. Ride-through capabilities can help support the bulk electric system rather than exacerbating the problem.

- The issue of "load masking" or "hidden load' will be avoided with DER Monitor/Manage. The real time DER visibility to DER generation output provides an understanding of masked load, so the Company can more effectively design and operate the system with knowledge of actual electric demand on a circuit without the contribution from DERs. This allows the Company's distribution system operators to safely perform system restoration without violating any equipment ratings or voltage limits.

DER Monitor/Manage Approach and Assumptions

DER Monitor/Manage is being proposed as a Foundational Investment for Rhode Island Energy. The plan is based on requiring the use of IEEE 1547-2018 IEEE standard for smart inverters interconnections. By having the smart inverter make small operational adjustments, DER developers and customers will be able to continue to operate DERs with reduced output compared to experiencing complete curtailment, which the Company will need to exercise at times to avoid system violations to maintain thermal and voltage compliance.[6] DER Monitor/Manage will benefit the entire system due to improved utilization, stabilization, and quality of power, which benefits all.

With each DER addition, there is an opportunity to gain visibility and fully integrate the DER into the distribution system at the time of interconnection. Alternatively, the DER becomes a lost opportunity where its operation can be detrimental to overall system safety and reliability if DER Monitor/Manage is not required through the interconnection process.

Because DER Monitor/Manage effects the safety and reliability of the entire system, the Company believes it is appropriate to implement DER Monitor/Manage as soon as practical and has included it within the GMP portfolio of the ISR as part of the GMP Foundational Investments. DER Monitor/ Manage is assumed to be available starting in 2026.

Since DER Monitor/Manage investments enable both DG and EV/HPs, it is difficult to assign the costs and responsibility to an individual customer. Also, DER penetration builds, it will be increasingly more difficult to attribute system changes to a particular DER interconnection. The

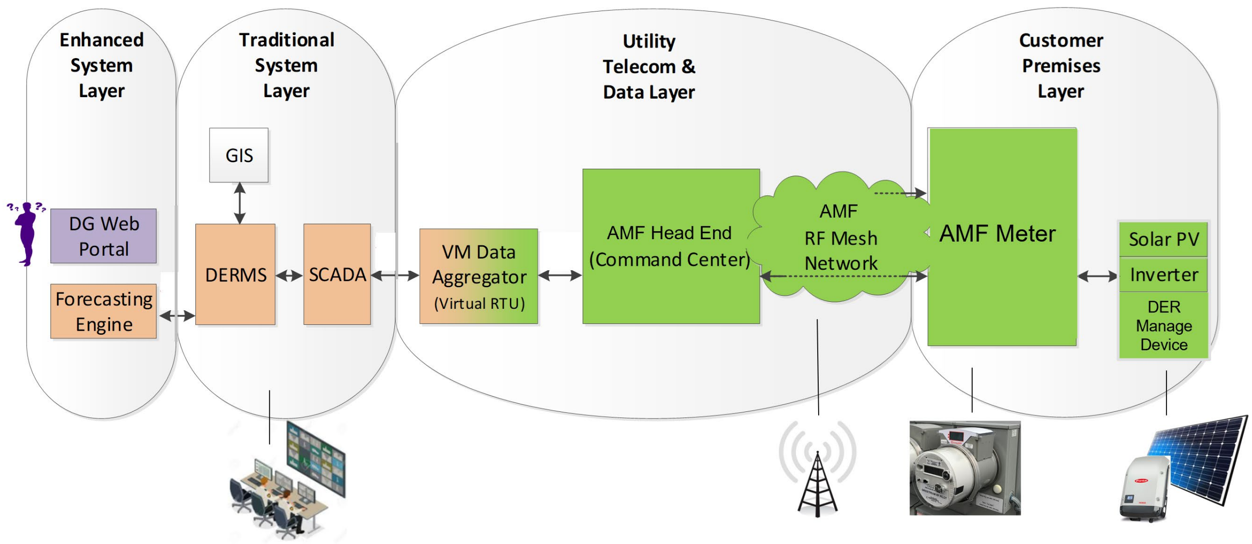
[6] Seasonal curtailment means the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the system design limitations of the system.

Company is including these proposed expenditures through the ISR because they 1) benefit all customers and the entire system, 2) enable all DER technologies, rather than benefiting just the interconnecting DER customers, and 3) the expenditure cannot be attributed to a particular DG interconnection therefore is not responsibility of the interconnecting DER under the current tariff. The DG interconnection tariff states that DG projects are only responsible for system modifications, which are solely required for their project.

DER Monitor/Manage Planning and Next Steps

The Company envisions that DER Monitor/Manage would apply to DERs interconnected with its distribution system by proactively implementing IEEE 1547-2018 requiring DER smart inverters to be certified the related Underwriters Laboratories ("UL") Standard 1741, "Inverters, Converters and Controllers for use in Independent Power Systems" ("UL Standard 1741"). Customers applying to interconnect new DERs will be required to: (1) use Company-approved smart inverters that are compliant with IEEE 1547-2018 certified with UL Standard 1741 and install devices that enable the Company to monitor and proactively manage DERs. This will enable the Company to better integrate, monitor, and manage DER resources. Qualifying DER system interconnections are envisioned to be equipped with: (1) smart inverters located at the customer premise; (2) DER management devices that interface to the smart inverter; and (3) local communication interfaces that utilize communication protocols that meet IEEE 1547-2018. For illustrative purposes, a DER Monitor/Manage Architectural Design is shown below in Figure G.2.

Figure G.2: Preliminary DER Monitor/Manage Architectural Design



- Smart inverters, among other things, provide grid support functions, including functionality such as fixed power factor, reactive power, low and high voltage and frequency ride through, power curtailment and remote ON/OFF capability[7]. This functionality allows the DERs that utilize smart inverters to operate in "sync" with the distribution system, thereby reducing power quality issues and maximizing potential DER output and operability. Smart inverters are also used in battery (energy storage) systems, electric vehicle chargers, and any other technologies that use DC power.

- DER management device is the link between the DER inverters and Rhode Island Energy. They would be installed and connected to the local communication interface of the DER system, so that the Company can monitor and manage the DERs and take advantage of the DERs' grid support functions.

[7] Inverters are devices used in DERs that convert the "DC" power from solar panels to "AC" power that can be transported on the electric distribution system for use in homes and businesses.

- Communications will either be RF mesh network that is proposed for AMF or cellular modems. Given the robust nature of the RF mesh network that will be in place for AMF, it is the preferred communication mechanism. Protocols to be used will be consistent with IEEE 1547-2018, being DNP, Modbus or 2030.5.

The components and architecture that has been used at PPL Electric for DER Management will inform the choices in Rhode Island. A DER architecture will be defined that will coordinate grid resources across customers, the distribution system, and transmission. It will contemplate contribution from DERs in normal and abnormal system conditions that are of different ages and sizes, including merchant DER, aggregators, and individual customers, utility DER and DR programs, and autonomous operating DER that use advanced inverter functions.

It should be acknowledged that DER Monitor/Manage technology is not fully mature. For example, many smart inverters are still in the process of being tested by UL to certify IEEE 1547-2018 compliance. The RF mesh system and AMF meters that are proposed for Rhode Island will be state-of-the-art, offering new approaches and technical solutions for DER Monitor/Manage that are more advanced than what has been available in the marketplace. To successfully implement DER Monitor/Manage, Rhode Island Energy will link DER assets with the ADMS-DERMS system. The DERMS platform is an extension of ADMS that incorporates DERs and offers functionality for power quality management and operational support. The ADMS roadmap presented in Section 6 includes a DERMS enhancement that is scheduled to be available in iterations starting with basic monitor and control capability at the end of 2025; forecasting capability at the end of 2027; load management/TVR, microgrid control at the end of 2028; and available for markets such as FERC 2222 in the future-term estimated 2029 or later. A DER Monitor/Manage plan will be defined that will consider the availability of these technical resources and solutions needed to complete the optimum architecture considering aspects such as cost, function, ease of use/scalability and security. In addition, the plan will include aspects such as organizational responsibilities, testing and validation, Data Governance Policy compliance, customer communication plan, RF mesh communication assessment, interconnection process implications, Customer portal implications and end-to-end readiness.

DER Monitor/Management Scoping and Filing Plans

The Company is assessing the legal and regulatory approvals necessary to permit DER Monitor/Manage and will make a separate filing for such approvals, including any tariff changes. In preparation, DER owners and interested stakeholders will be consulted to get input and feedback for the plan. The Company anticipates that the DER Monitor/Manage filing will be made urgently after filing the GMP, collecting stakeholder feedback and clarifying the necessary approvals that will be required for implementation.

Attachment H

Attachment H:

GMP Deployment Plan

Table of Contents

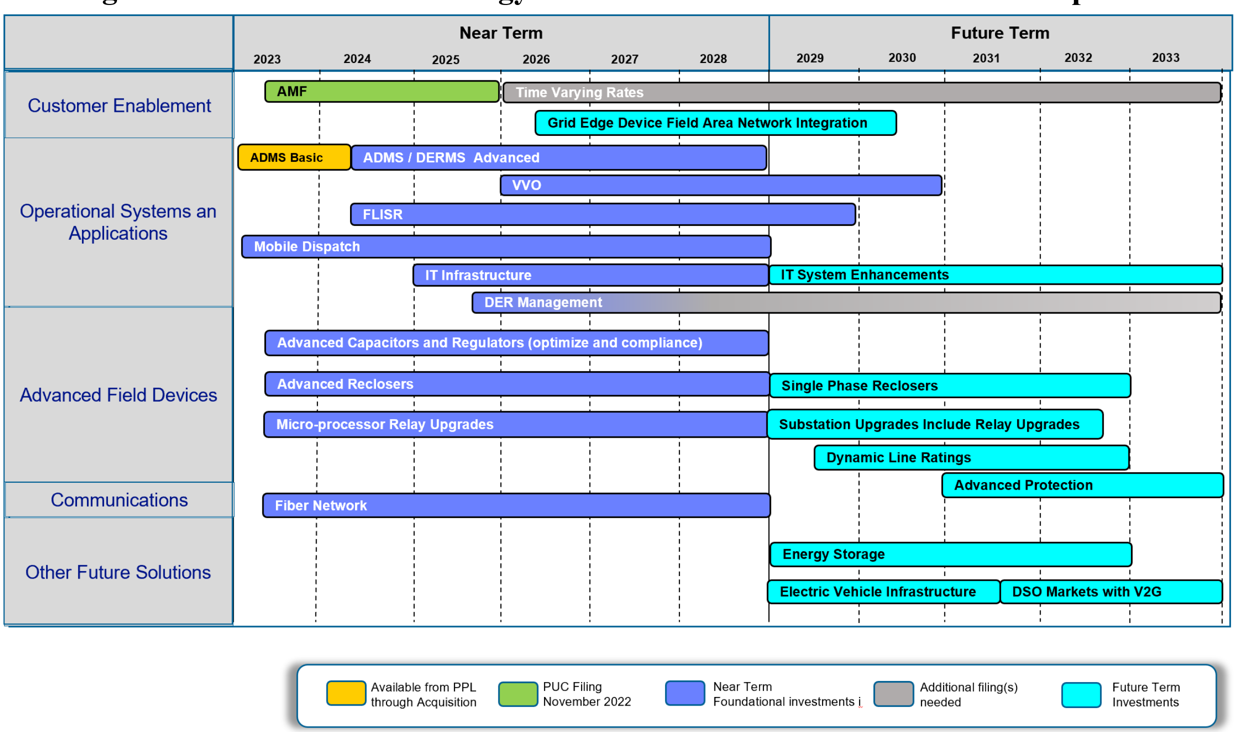
1. Overview

Deployment Plan Approach

The execution of the GMP Deployment Plan will be a primary focus of Rhode Island Energy over the next several years, as a significant investment is being proposed that will deliver numerous benefits for Rhode Island Energy customers. The GMP initially focuses on foundational elements of a future grid that can be enhanced as needed over time to deliver new functionalities where and when they are needed. Implementation of specific solutions will deliver initial foundational functionalities including investments in Advanced Field Devices include capacitors and regulators, reclosers, and microprocessor relays, while at the same time upgrading the IT Infrastructure and extending the Fiber Network; followed by the development and deployment of new software and operational technology investments including ADMS-based application solutions (i.e., FLISR, VVO/CVR, and DERMS), DER Monitor/Manage, and Mobile Dispatch.

Figure H.1 below provides the Grid Modernization Roadmap that summarizes the solutions and expected timing of GMP investments through 2033:

Figure H.1: Rhode Island Energy Grid Modernization Solutions Roadmap



Vendor/Supply Chain

Rhode Island Energy will require external assistance from vendors with extensive experience and/or specialized services to meet the resource needs of the GMP. Rhode Island Energy and PPL will be leveraging many existing strategic partnerships that have been established over the years. Pre-established contracts and relationships that can be leveraged will be executed through either sole-source or competitive bid contracts to derive efficiency, scalability, and cost-effectiveness. This approach and these various alternatives to securing critical and basic material and equipment is consistent with industry best practices.

Vendors will be needed to supply advanced field devices including advanced capacitors and regulators, advanced reclosers, microprocessor relays, and ancillary equipment. The expansion of the fiber network will require more specialized vendors with fiber installation experience. Vendor contracts will also need to be procured for the various ADMS-based applications being employed including VVO/CVR, FLISR, and DERMS, as well as DER Monitor/Manage and Mobile Dispatch. While many vendor relationships exist that have delivered similar material in the past, significant increases in quantities will put pressure on these vendors to expand their production capabilities, and yet new vendor relationships may need to be explored to ensure successful delivery. Once contracts are in place, the responsibility for the day-to-day management of vendors will lie with GMP project governance described below.

Supply chain issues have been exacerbated over the last few years and utility industry equipment and material has been no exception. The Company is seeing longer lead times for a variety of materials and has adjusted schedules and business practices to ensure projects are completed on schedule. Orders will be placed for long-lead time materials and equipment to ensure equipment installation in accordance with the project timeline can be met.

Among other items, reclosers and wood poles are two examples where the Company has made execution adjustments. The Company recognized recloser lead times are now eight months. As a result, the Company, working with PPL procurement, has locked down approximately 80% of the production slots for the CY 2023 plan and expects to lock down the balance in early January. Similarly, the Company recognized delivery issues with wood poles and found alternative suppliers to ensure adequate stock levels were maintained. The Company is planning for procurement earlier than before to ensure required dates are met. These longer delivery timeframes and costs are being taken into consideration when planning the execution of the proposed FY 2024 Electric ISR Plan and implementation of the Foundational Investments, where multi-year commitments will help to ensure availability because manufactures can plan accordingly.

Project Governance

Rhode Island Energy will utilize a GMP Project Governance Model to define the structure, process, methods and interfaces to manage and oversee GMP implementation. It provides an organizational framework to enable the completion of a successful deployment and overall implementation of these leading-edge solutions to build a state-of-the-art electric distribution grid. A project governance structure ensures that responsibilities, decision-making authority, and processes for the project are clearly defined, mechanisms to execute are communicated, the activity is coordinated across the organization and accountability for project success is understood.

- Executive Steering Committee - serves as project sponsor and strategic decision-making group. This committee's purpose is to provide overall governance and approval of all major policy, strategy, and financial decisions. There ongoing responsibilities are to ensure organizational goals are aligned, necessary resources are assigned, and organizational issues are resolved to ensure successful project completion and execution. This committee will include representation from senior leadership and key project team members.

- Program Management Office ("PMO") - serves as primary project leadership whose main purpose is to plan and execute the project in its entirety, including day-to-day project oversight and management. They are responsible for the successful deployment and integration of all aspects, deliverables are within scope, schedule, and budget, and achievement of strategic and operational objectives. The PMO will also manage all administrative project functions including developing the overall project plan, work schedules, leadership meeting calendars, and operational and execution metrics.

- Work Execution Teams – serve as the bulk of the project management team that carry out the day-to-day work activities of the project. The core responsibilities of these teams include the development and execution of detailed work activities, managing scope in coordination with the PMO, resolving both technical and managerial issues, and tracking progress to plan.

Benefit Summary

As explained in various sections of the GMP Business Case, all solutions are interrelated to each other and enable various benefits. For example, to derive the maximum benefit from advanced field devices, ADMS including DERMS, FLISR, and VVO are critical software systems and applications that provide a complete automated solution utilizing vast quantities of data from AMF and various communications networks that balance supply and demand on the grid, optimize grid utilization, and significantly improve both reliability and worker safety. This set of integrated

GMP solutions will produce a state-of-the-art electric distribution grid that enables the achievement of the Climate Mandate, advances technology to meet the demands of ever-increasing DER penetration, provides customers information and choice over their energy choices at an unprecedented level, and builds a resilient and reliable grid for Rhode Island Energy's customers.

Cost Summary

The estimates for each GMP solution that have been included in the Foundational Investments as referenced in Section 6.1 - Fig. H.2, are shared again below. Figure H.2 reflects only the project/investment costs for the GMP. The cost estimates in the benefit-cost analysis include all the costs of deploying the grid modernization solutions, including CAPEX, OPEX, and Run-The-Business ("RTB") costs like software maintenance fees and equipment maintenance. As shown, investments in Advanced Field Devices (Advanced Capacitors & Regulators, Advanced Reclosers, Microprocessor Relays), Fiber, and IT infrastructure are the primary cost drivers for the Foundational Investments where the Company estimates investing nearly $339.9 million for all GMP investments through fiscal year ("FY") 2028, depending on customer DER adoption. These costs would be recovered through the Company's annual ISR plan filings, current and future rate cases, and special proceedings.

Table H.2: Foundational Investment Estimates through 2028

Program Category	Project Costs (000's)			
	Install	Remove	OPEX	Total
Communications (Fiber)	$ 68.6	$ 0.7	$ 0.7	$ 70.0
Advanced Field Devices	$ 191.4	$ 10.2	$ 5.3	$ 206.9
Operational Systems & Applications	$ 39.4	$ 0.3	$ 0.3	$ 40.0
Total Distribution Project Costs	**$ 299.4**	**$ 11.1**	**$ 6.4**	**$ 316.9**
Transmission Fiber	**$ 22.5**	**$ 0.2**	**$ 0.2**	**$ 23.0**
Total All GMP Investments	**$ 321.9**	**$ 11.4**	**$ 6.6**	**$ 339.9**

GMP Solutions Portfolio Summary

The remainder of this document presents the deployment plans for each solution that creates the Grid Modernization Plan ("GMP") portfolio. Each section in this document summarizes the Company's current plans for a particular solution and generally follows the outline below except for AMF (AMF has been filed as a separate docket). Additionally, deployment priorities are discussed only for advanced field devices to be installed on the electric distribution system including advanced capacitors and regulators, advanced reclosers, and microprocessor relays:

- **Background:** current state, limitations, why the solution is needed
- **Objectives:** what the Company plans to accomplish for each solution
- **Benefits**: summary of the key benefits of the solution
- **Deployment Priorities:** deployment criteria and prioritization methodology
- **Schedule & Cost Estimate:** quantities/volume planned and total cash flow by year

This Deployment Plan is a living document that will be reviewed and updated on an ongoing basis. Some plans that represent near-term investments are more detailed, while others that represent longer-term investments are less detailed due to being earlier in the stage of development. Plans and cost estimates will be refined over time and the closer an investment gets to implementation, the more detailed and precise the plan and cost estimate will become.

2. Advanced Metering Functionality ("AMF")

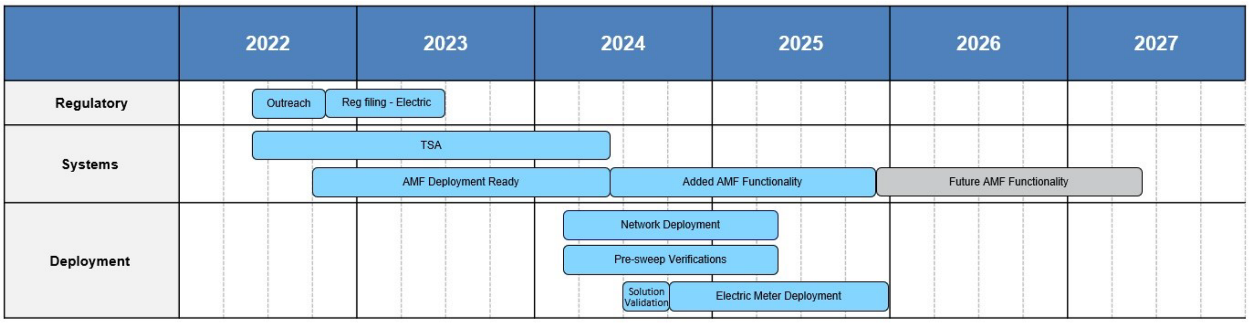
AMF is a prerequisite to this GMP. As such, the AMF Business Case was filed with the Rhode Island Public Utilities Commission in November of 2022. There is no funding being requested in this filing for AMF investments.

The granular data[1] that is captured, stored, and transmitted via hundreds of thousands of new, state-of-the-art, advanced digital electric meters, is integral to not only providing more choice for consumers in managing their energy needs, but also to an effective and efficient future electric grid that improves safety and reliability for consumers and communities.

The GMP solutions as part of this plan and business case have been strategically and carefully planned to be deployed and subsequently integrate with these new AMF meters that are planned for completion by the end of 2025. For reference, the AMF Project timeline is provided below as Figure H.3.

[1] Granular data is detailed data, or the lowest level that data in a target set. The granularity of AMF data is provided for through the availability of 15-minute interval, time sequenced data measurements. This level of measurement is much finer than historically offered making richness of information available for improved analytics and greater operational visibility.

Figure H.3: AMF Project Timeline



AMF granular data will enhance the GMP solutions proposed in this business case to produce a leading-edge electrical grid that will serve the customers of Rhode Island Energy for decades to come.

3. Advanced Capacitors and Regulators

Background

For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range. The Company is obligated to follow ANSI voltage standards for maintaining acceptable levels of voltages where the customer is interconnected to the distribution system. The service voltages should be within ±5% of the nominal voltage. Currently, the Company relies primarily on traditional voltage regulation equipment such as a load tap changer ("LTC"), mid-line voltage regulators, and capacitors for voltage regulation installed on the primary side of the distribution circuit.

In the past, voltage regulation has been relatively predictable. Since electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. These simple autonomous settings, however, will be insufficient to maintain compliance with voltage standards for feeders with a high level of intermittent renewable generation and two-way power flows. The shortcomings of traditional voltage regulation equipment are limited number of operations per day, lack of fine control on voltages, and indirect control over secondary voltages evident with the higher penetration levels of distributed generation and electric vehicle charging loads. Specifically, load-based DERs, such as EVs, are forecasted to create under-voltage issues during peak load periods, and generation-based DERs, such as solar and wind DG, are forecasted to create overvoltage during light load periods.

Objectives

The proposed Advanced Capacitors & Regulators would adjust system voltages up or down in a dynamic manner to accommodate the variable output of these DER technologies. In addition, the voltage control and near real-time power measurements provided by these devices enable engineering and operations personnel to better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all Rhode Island Energy customers through optimization (e.g., VVO/CVR).

Benefits

As a result of dynamic adjustment of system voltages, advanced capacitors and regulators serve to maintain compliance with service voltages to within the acceptable ANSI range of +/- 5%. This technology automates voltage regulation that has historically been performed manually by distribution system operators and technicians physically deployed to specific feeders experiencing under- or over-voltage conditions, thereby lowering labor and distribution system operating costs.

Deployment Priorities

One solution in the GMP consists of adding smart capacitor controls to existing fixed and switched capacitor banks, and new smart capacitors and regulators to distribution feeders to control voltage and achieve VVO benefits. Installation prioritization will be based upon reduced peak demand and energy conservation (including DRIPE effects). Settings will be automatically adjusted remotely in real time with the VVO software. In some cases, existing fixed and switched banks will be retired in place or relocated based on VVO analysis.

The AMF filing includes RF mesh communications network and AMF meter deployment starting in 2024 using a sector-by-sector approach, activating specific geographic sections at a time to company information and operating systems. These new meters or endpoints will provide thousands of pieces of data at a time containing granular voltage information that will serve to inform company distribution system operators and engineers of voltage irregularities and other critical system information that will provide significant visibility of distribution system characteristics and issues that have never been known before. This will provide incredibly useful information that will pinpoint issues and help determine priority locations for capacitors and regulators to be installed within each sector as defined in the AMF filing. Installation of Advance Field equipment will be coordinated to achieve the BCA benefit objectives where 20% of the VVO benefits start in 2026 and progress to 100% by 2030.

Schedule and Cost Estimate

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total Cap Banks	135	180	165	165	163		**808**
Total Regs	11	14	15	15	15	10	**80**
Total Cap Bank and Regs Install Cash Flow	$ 4,635,000	$ 6,260,760	$ 6,075,101	$ 6,214,828	$ 6,298,627	$ 1,008,372	**$ 30,492,688**
	17%	22%	20%	20%	20%	0%	

This program is included in the FY2024 Electric ISR Plan.

4. Advanced Reclosers

Background

The distribution system has traditionally been built to ensure adequate available capacity at all times by building the necessary distribution system capacity to accommodate forecasted peak loading on extreme weather days in accordance with the Company's planning criteria. Designing the system to meet these worst-case scenarios assuming one-way power flow eliminated or lessened the need for day-to-day load management for distribution grid management. In addition, when a fault does occur on the system, restoration is performed by manually switching to isolate the fault and serve customers with power from alternative sources where possible. As DER penetration increases and is located anywhere on the distribution system it will result in possible two-way power flow, overloads in the reverse direction under light load conditions, and desensitization of protection systems during fault conditions. Similar to voltage management, the increasing complexity of the grid will require a transition away from simple autonomous controls to control schemes that are integrated across an entire feeder.

Objectives

The load control and near real-time power measurements provided by Advanced Reclosers when used in combination with ADMS enable engineering and operations personnel to automatically isolate faults and restore service (FLISR) to better manage capacity along individual feeders, ultimately resulting in lower costs to all Rhode Island Energy customers through optimization.

The targeted deployment of Advanced Reclosers is forecasted to reduce both the duration and frequency of outages. Additional reclosers will provide more feeder segments, which will result in fewer customers experiencing sustained outages when a fault occurs. Having more segments also makes it faster to locate faults, which can reduce outage time for all customers, even those in the faulted segment. In addition, software with overlaying control schemes to coordinate multiple Advanced Reclosers on a feeder to achieve fast, reliable, and safe fault location, isolation, and service restoration (FLISR) can be incorporated for additional customer benefits where it is cost beneficial to do so.

Benefits

As illustrated in Section 6.4 and further discussed in Section 8 in conjunction with the BCA, Rhode Island Energy can expect up to a 30% reduction in outages (SAIFI improvement) across its electric distribution system because of the installation of advanced reclosers coupled with ADMS-Basic that features the FLISR application. Additionally, advanced reclosers also support or enhance several other key functionalities, including improved system visibility, flexibility for system configuration, enhanced protection capability, voltage data to improve volt/VAR optimization analysis, and operational efficiencies. Distribution Grid Control and Reliability functionalities result in the quantified benefit impacts summarized below.

- OPEX Labor Efficiency (when coupled with ADMS and other supporting solutions) due to the ability for the distribution system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise.

- Avoided D-System Infrastructure Cost (when coupled with Advanced Capacitors & Regulators, ADMS, VVO/CVR platform, and other supporting solutions) due to the ability of the distribution system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs, rather than investing in traditional “wires” solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.

- Reduced Outage Restoration Time (when coupled with ADMS, FLISR, and other supporting solutions) by enabling the distribution system operator and control system to quickly locate and isolate a fault and restore power rather than waiting for field crews to locate a fault and restore power. Benefits are based on the monetization of customer impacts as presented in the DOE ICE Calculator.

- Reduced DER Curtailment (when coupled with ADMS, DERMS, and other supporting solutions) due to the ability of the distribution system operator to optimize power output from renewable DER, by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance.

The recommended plan enables the Company to ensure loading levels and protection systems are sufficient across all times of a year and in all areas of the distribution system with various levels of customer DER adoption. Load and protection management are fundamental utility requirements for safe and reliable electric service. The GMP enables this fundamental requirement by integrating technology to more granularly manage the grid rather than simply building additional T&D capacity that is under-utilized during most of the hours in a year.

The Interruption Cost Estimate ("ICE") Calculator was used to calculate the benefits of the improved reliability. It is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements. Details are provided at: https://www.icecalculator.com/home.

Deployment Priorities

GMP Advanced Reclosers will be deployed on Rhode Island Energy feeders based primarily on SAIFI performance (outage frequency). In addition, a secondary consideration is the DER penetration on each feeder since DERs reduce available fault current and can desensitize protection equipment. Location will be based upon advancing the long-term design configuration of each feeder – typically four mainline and two tie-line reclosers per feeder.

Before the recloser installation, appropriate protection studies will be performed consistent with the normal Rhode Island Energy engineering and design process to ensure proper coordination – as it is performed today when any modification is made to a distribution feeder that affects its electrical characteristics.

Schedule and Cost Estimate

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total Recloser Quantity	222	315	315	315	315	79	**1561**
Total Recloser Install Cash Flow	$ 17,404,800	$ 25,264,008	$ 25,845,080	$ 26,439,517	$ 27,047,626	$ 6,939,390	**$ 128,940,422**
	14%	20%	20%	20%	20%	5%	

This program is included in the FY2024 Electric ISR Plan.

5. Microprocessor Relays

Background

Generation, transmission, distribution, and their regulation continuously evolve. The equipment monitoring and protecting the power system needs to be flexible to meet these changes. Rhode Island's 2021 Act on Climate set enforceable, statewide, economywide greenhouse gas emissions mandates to achieve net-zero emissions by 2050. The 2022 amendments to the Renewable Energy

Standard further specify a schedule of electricity to be generated by 100% renewable energy resources by 2033. This transition will remove the inertia-based generation that has long stabilized system frequencies and replace it with variable sources that require more intelligent monitoring devices. Intelligent and automated decision-making is becoming more important than ever for Rhode Island Energy to maintain operating costs, safety, and provide electric service reliability. Electro-Mechanical Relays, which are predominate in substations, are dated and provide little data or flexibility that will be needed to manage and operate in the future.

Objectives

Digital relays (microprocessor relays), adapt to power flow changes and other changes in system conditions with flexible settings, custom logic, and multiple settings groups. Additionally, the fault location information provided by digital relays minimizes outages and reduces the time field technicians spend searching for issues. Improving how the power system is monitored and controlled can provide operations and maintenance benefits that exceed the initial capital investment.

Benefits

There are many advantages to upgrading old electromechanical, solid-state, and first-generation electromechanical relays. Reliability improves because there is less direct wiring and interconnection wiring. Reliability and security of multifunction logic and settings are improved with next-generation user interface software. Remote input/output modules, remote analog/digital inputs, and thermal measurement capabilities have expanded protection, control, and monitoring capability. New protection and monitoring features improve power system equipment life and increase personnel safety. Maintenance costs are reduced, while internal watchdogs alert the user if the relay has a problem. Settings groups can be changed instantaneously to adapt to varying power system requirements. Digital relays offer a variety of secure communications capabilities for interfacing with Smart Grid controls, SCADA systems, and business networks. Event memory is larger for more on-board, standardized oscillographs and event reporting. Data from the upgraded relays is used in conjunction with software to predict failures before they occur, respond faster to incidents, and integrate data with business processes to make the Company more efficient and reliable which will result in customer savings, improved services, and increased customer satisfaction.

Deployment Priorities

There are five categories of microprocessor relays that make up the portfolio of installations and upgrades that will be performed on the Rhode Island Energy electrical distribution system. They are as follows:

- Category 1: These relay replacements will utilize the existing PPL standard where the relays come pre-wired within an outdoor enclosure. Using an existing standard will allow for quick implementation. The number of relays in this category is 32.
  - In Service Projection is 50% - Spring 2024
  - In Service Projection is 100% - Spring 2025

- Category 2: These relay replacements will require a new standard to be developed due to the substation equipment being incompatible with the PPL relay standard described in Category 1. These relays will be installed within the breaker itself as opposed to being in a separate enclosure. The number of relays in this category is 87.
  - In Service Projection is 25% - Fall 2024
  - In Service Projection is 75% - Fall 2025
  - In Service Projection is 100% - Spring 2026

- Category 3: These relay replacements will require a new standard to be developed and is expected to be finalized after the Category 2 standard. This new standard will be for substations that have indoor circuit breakers and relay panels where a full relay switchboard panel design is required. The number of relays in this category is 52.
  - In Service Projection is 25% - Spring 2026
  - In Service Projection is 50% - Fall 2026
  - In Service Projection is 100% - Fall 2027

- Category 4: These relay replacements will require the station to be rebuilt or relocated due to existing space constraints within the substation yard making it not feasible to replace the relays within the same footprint. Due to the complexity of this work, these relays will be replaced after 2028. This is high level and will be refined as we progress with scope development. There are no quantities in the Foundational Investments in this category.
  - In Service Projection is 20% - Fall 2029
  - In Service Projection is 50% - Fall 2030
  - In Service Projection is 75% - Fall 2031
  - In Service Projection is 100% - Fall 2032

- Category 5: This category includes all existing digital relays that will need to be reprogrammed to include additional safety and data gathering capabilities. This reprogramming includes, but is not limited to, adding hot line tag and various SCADA indications on why the device tripped for FLISR. As this is purely a reprogramming of existing digital relays and therefore, an operating expense, there are no quantities to be installed in this category.

- Work to be completed - Spring 2024

All Category 1 and Category 2 installations (low-cost sites) will be initially targeted for replacement. This represents about 17% of the current inventory of electro-mechanical feeder relays. The remaining relay upgrades will occur in the future as an add-on item when the associated substation is being rebuilt for other reasons. This is expected to occur over the next 15-20 years.

Schedule and Cost Estimate

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total Electromechanical Relay Quantity	19	26	45	46	17	18	**171**
Total Electromechanical Relay Install Cash Flow	$ 2,040,000	$ 2,852,942	$ 5,053,479	$ 8,564,133	$ 6,735,144	$ 6,721,418	**$ 31,967,116**
	11%	15%	26%	27%	10%	11%	

This program is included in the FY2024 Electric ISR Plan.

6. Advanced Distribution Management System ("ADMS")

This project will apply only to ADMS advanced applications. It builds up functionality that is provided in ADMS Basic[2] in a phased approach. These ADMS-based application solutions are defined in Section 6. Additional deployment details are provided below for FLISR, VVO/CVR, DERMS and Adaptive Protection:

[2] ADMS Basic is the ADMS platform PPL currently has in place for its other utilities, and which Rhode Island Energy will have in place for its operations upon exit from the Transition Services Agreement with National Grid USA Service Company, Inc. As part of the Acquisition approval, PPL committed that it would not seek recovery from customers of any transition costs. Part of that transition includes bringing ADMS Basic to Rhode Island Energy. Accordingly, PPL is providing the ADMS Basic platform to Rhode Island Energy, the allocated costs of which will not be recovered from Rhode Island customers. ADMS Basic is a significant enhancement to the National Grid distribution management system. PPL and Rhode Island Energy plan to propose enhancements to ADMS Basic (which are not a part of the transition) to increase functionalities and benefits. In this AMF Business Case, the defined term ADMS Basic refers specifically to the software that PPL is providing to Rhode Island Energy as part of the transition.

- Fault Location, Isolation, and Service Restoration ("FLISR")

  ADMS-based FLISR application - Software with overlaying control scheme to coordinate multiple load management devices (i.e., Advanced Reclosers & Breakers) on a feeder to achieve fast, reliable, and safe FLISR, which can reduce customer outage restoration time.

- Volt-Var Optimization ("VVO")/Conservation Voltage Reduction ("CVR")

  VVO/CVR Platform - Accelerated deployment of software with control schemes to coordinate multiple voltage regulating devices (i.e., Advanced Capacitors & Regulators) on a feeder to achieve optimal CVR performance and reduce customer demand and energy use.

- Distributed Energy Resource Management System ("DERMS")

  DERMS - Suite of software tools that is necessary for DER Monitor/Manage to integrate customer controlled DER resources with grid operations, including dispatching DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution.

- Arc and Flash Protection

  ADMS-based Adaptive Protection - Software that will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices to ensure worker safety and the reliable operation of the grid. This functionality is long-term and not included in the Foundational Investments.

Background

Currently, distribution system operators rely on static system models and the distribution status information in SCADA (where available) to make operating decisions. For planned and emergency feeder reconfigurations, the distribution system operators utilize historic peak loading and nameplate data to help predict future conditions. Historically, system loading patterns have been somewhat predictable with regions, substations, and even individual feeders generally following similar trends. This is changing with the proliferation of DER, EV charging, and gas to electric heating conversion where daily, seasonal and locational variability is increasing. In addition, any advanced automation schemes (e.g., VVO/CVR) have been difficult to develop and are currently built as stand-alone functions to the extent the capability is available. The distribution system operators can monitor the actions of the programs via the SCADA system, but they run independently based on "as-designed" feeder configurations rather than adapting to the real-time "as-switched" feeder configuration, meaning that automation schemes may be disabled if the distribution grid is out of its normal state. Finally, the Company aspires to expand the number of field devices that will be integrated with the existing SCADA system which will significantly increase the amount of data brought back from distributed devices. As a result, existing capacity will be strained and capabilities will be needed that exceed existing applications. The distribution system will no longer be able to be operated in a safe and reliable manner without a robust ADMS/SCADA system capable of facilitating the following primary functionalities; OMS, FLISR, VVO, DER Monitor/Manage, Control, and Power Flow, Auto-reconfiguration, etc.

Objectives

A condition that accompanied the PPL acquisition of Narragansett was to provide the ADMS Basic as a condition of the sale where deployment was named on the Transition Service Agreement (TSA). The strategy is to align Rhode Island ADMS systems to mirror the current ADMS architecture and functions that PPL has used as close as possible. The scope of this investment includes incremental ADMS functionality being developed beyond ADMS Basic to satisfy Rhode Island Energy requirements where various functionalities will be phased in as a result of the Foundational Investments as described in Section 6.

Benefits

The proposed ADMS investment is software that is dependent upon integrated information from advanced field devices and AMF meters to provide the Distribution Control Center operations greater visibility, situation awareness, and optimization of the electric distribution grid as well as improved efficiencies through automating multiple control center processes. The Company believes ADMS is a critical platform for the integration and operational management of DERs as their impact on grid performance grows, and ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices, DERs, and AMF data as it becomes available. For example, when planning to reconfigure the grid, ADMS will allow the distribution system operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach and ensure the most efficient switching that yields optimal power quality. DERs will be operationally integrated into the ADMS to allow distribution system operators to assess their effect on the grid, as well as leverage them for support where possible.

Schedule and Cost Estimate

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total ADMS Install Cash Flow	$ 105,000	$ 140,000	$ 3,159,888	$ 1,568,613	$ 4,387,338	$ 2,168,250	**$ 11,529,088**

The project will be implemented utilizing a phased approach to develop different application modules that yield incremental functionality with the Foundational Investments through 2028. This will maximize value add and benefits realization as early as possible. To date, the Company has completed an analysis and scoping effort for the development of the Rhode Island Energy ADMS expansion which is described in Section 6. This program is included in the FY2024 Electric ISR Plan. ADMS Basic is provided by PPL to the Company as part of the transition.

7. DER Monitor/Manage

Background

The transmission and distribution system in Rhode Island is currently undergoing significant changes due to the increasing deployment and use of DER, upending the traditional electric grid architecture that has been supplied with centralized, large-scale generation located at significant distances from customers. By allowing customers to both consume and produce electricity at what were traditionally points of delivery, DER force the electric distribution system to perform in a way for which it was not originally designed and, as a result, places an increasing stress on the grid.

As DER in Rhode Island continue to increase, the Company still must provide reasonable, safe, reliable, and affordable electric service to all of its customers, including those who have not installed DER. This can be particularly difficult because electricity cannot be readily stored and generation and load must be balanced at all times. Today, transmission operators, such as ISO-NE, manage the transmission grid by maintaining a balance between demand and generation by monitoring and controlling generation assets instantaneously. Traditionally, distribution operators did not have to worry about balancing demand and generation because the distribution grid had very little generation connected to it. However, as the penetration level of DER increases, the classical model of distribution systems, not well-equipped to handle the simultaneous balancing of demand and generation, will need to change in the future to ensure system stability.

Therefore, as distribution systems become increasingly similar to transmission, i.e., a mix of demand and generation, the need to balance generation and demand becomes critically important.

Such balancing cannot be accomplished without the ability to monitor and manage generation assets on the grid.

Objectives

As more DER are interconnected with the Company's distribution system, Rhode Island Energy will have to balance demand and generation simultaneously and will increasingly experience issues on its distribution without having the ability to monitor and manage those resources. Solar and other intermittent resources can negatively affect the voltage on the electric distribution system, resulting in delayed interconnection or distribution system reinforcements before additional DER can be installed. Given Rhode Island Energy's current inability to directly communicate with and manage DER to mitigate resulting power quality issues and to leverage grid support functionality, the amount of intermittent generation that can be interconnected must be limited to maintain system stability and reliability. Moreover, in the absence of such ability, the reliability, safety, and efficiency of Rhode Island Energy's service will be placed at increased risk with each new DER that is interconnected with the distribution system.

Benefits

The Company uses the term "grid modernization" to refer to those investments associated with managing the distribution system with more granularity to create a platform of solutions that enables more DERs to connect, while also giving customers more control over their energy decisions, reducing energy use, and improving reliability. As more DERs connect to the system, the devices need to be integrated with utility operations at all levels for management and monitoring purposes.

Many utilities have experienced operations and planning challenges as DER penetration becomes increasingly significant. These challenges include, but are not limited to, voltage swings, masked or hidden load, limited hosting capacity, planning uncertainties, and protection/operational challenges with two-way power flow. In response to these challenges, the IEEE 1547-2018, which set forth requirements for smart inverters that can help support the distribution system. When these smart inverters are coupled with DER management devices, the IEEE standard provides electric utilities with the ability to monitor and manage DERs interconnected with their distribution systems. See Attachment G.

Schedule and Cost Estimate

The DER Monitor/Manage application will be placed in service incrementally as components of the GMP are completed. The deployment plan was developed based on the projected DER connections by year and the cost per connection.

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total DER Monitor Manage Quantity	-	-	-	4,017	8,034	8,787	**20,838**
Total DER Monitor Manage Install Cash Flow	$ -	$ -	$ -	$2,288,076	$ 4,043,598	$ 4,414,290	**$ 10,745,964**
	0%	0%	0%	19%	39%	42%	

This program is included in the FY2024 Electric ISR Plan.

8. Mobile Dispatch

Background

Today, dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS (Outage Management Systems) to view customers calls and predicted outage locations. They prioritize "trouble calls" and outages and assign them to appropriate field crews based on capability and location as optimally as possible. This is performed remotely at dispatch centers without the benefits of real-time knowledge of actual outages and locations of field crews.

Objectives

The implementation and integration of the ADMS-based Mobile Dispatch application with OMS will allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews and crew time and shorten "trouble calls" and outage response times. In addition, field crews will be able to update details concerning their time of arrival, incident details once on location, and estimated restoration times rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near-real time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand.

Benefits

The Mobile Dispatch application will be placed in service incrementally as components of the GMP are completed. Mobile Dispatch is expected to improve outage restoration times, the efficiency and accuracy of restoration efforts, and worker safety.

Schedule and Cost Estimate

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total Mobile Dispatch Install Cash Flow	$ 73,500	$ 98,000	$ 171,500	$ 196,000	$ 196,000	$ 49,000	**$ 784,000**

This program is included in the FY2024 Electric ISR Plan.

9. Information Technology ("IT") Infrastructure and Cyber Services

Background

Managing the distribution system more granularly in order to safely, reliably, and cost effectively meet customer's evolving expectations will depend on the Company's ability to manage, analyze, and share underlying information or data. Managing high levels of DER integration while ensuring electrical network stability and performance will rely on deeper and faster insight into asset performance, operating conditions, and customer demand. As the Company deploys more Advanced Field Devices, AMF, and other technologies, there will be an enormous growth of incoming data.

Objectives

The IT Infrastructure Plan includes investments that will build foundational data management capabilities by enabling enhanced data governance across key datasets including an enterprise integration platform that will provide all the necessary system integrations and associated data protection.

Benefits

The proposed underlying IT infrastructure investments in data management are necessary to enable grid modernization functionalities and realize its full benefits. The Company considers cybersecurity a necessary capability in order to operate a safe, reliable and cost-effective electric distribution system as discussed in Section 7.4 and further described in Attachment J. Cybersecurity protects customers and electric grid operations from a vast array of threats. As more intelligent devices, including third-party devices, are interconnected and integrated with utility operations, the number of potential targets increases, as does the need for a robust cybersecurity program.

Schedule and Cost Estimate

The IT Infrastructure will be placed in service incrementally using the impact assessment described in Attachment J and as components of the GMP are completed.

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total IT Infrastructure Install Cash Flow	$ 1,514,100	$ 2,018,800	$ 2,998,800	$ 4,281,620	$ 4,837,280	$ 757,050	**$ 16,407,650**

This program is included in the FY2024 Electric ISR Plan.

10. Communications - Fiber Network

Background

Currently, leased cellular communications is used to communicate with automated devices in substations and with automated devices that have been installed on distribution lines. Leased cellular service is limited in bandwidth and is subject to greater interference, especially during emergencies when communication is imperative.

With the proliferation of GMP and AMF automated devices, there is a significant need to send data to/from these devices to software systems and customer portals quickly to visualize, monitor, and manage the distribution system and interact with customers in near-real time. Cellular, especially when used as a back-haul carrying significant data traffic that is critical to operations, adds reliability and resiliency system risk.

Objectives

The GMP is proposing for Rhode Island Energy to own, operate and maintain a private fiber network in Rhode Island to support communications to substations where it will be used to back-haul information from substations that includes AMF data. This investment will replace leased cellular services that currently provide back-haul communications for substations.

Benefits

Replacing cellular services connecting substations with fiber optic cabling will significantly improve data flow, reliability and resiliency of communications. This ensures maximum effectiveness of the many GMP components, technologies, and systems that are working in sync to deliver safe, reliable, and affordable power.

Schedule and Cost Estimate

The backhaul fiber network will consist of 100 miles of fiber that is a shared facilitate between bulk Transmission and Distribution where 92 miles of distribution and 8 miles across water are included in the Foundational Investments. The remaining 46 miles of fiber for Transmission will be proposed through NEPOOL because it is a looped facility, where costs will be shared across the members. Rhode Island Energy's portion of this cost would be approximately 7% of the $23M because it is defined as a Pool Transmission Facility (PTF), based upon Rhode Island's load ratio share. The deployment of this network will reduce Rhode Island Energy's annual O&M costs. The cost and benefits of the Rhode Island Energy GMP fiber network are included in the BCA analysis. The fiber network will be placed in service over the period addressed by the Foundational Investments.

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Total Distribution Fiber Miles	11	18	36	27	4	4	**100**
Total Distribution Fiber Cash Install Flow	$ 8,104,600	$ 11,348,400	$ 17,875,200	$ 15,278,200	$ 7,996,800	$ 7,996,800	**$ 68,600,000**
	11%	18%	36%	27%	4%	4%	

Program Category	2024 (4/1/23 - 12/31/23)	2024 (1/1/24 - 12/31/24)	2025	2026	2027	2028	Total
Transmission Fiber	$ 3,285,714	$ 4,380,952	$ 7,666,667	$ 7,666,667	$ -	$ -	**$ 23,000,000**

The distribution investments for this program are included in the FY2024 Electric ISR Plan. The Transmission Fiber investments do not get submitted via the ISR plan.

GMP Benefit-Cost Analysis (BCA) Spreadsheet

CONFIDENTIAL

The Company provided GMP BCA Analysis Spreadsheet as an Excel document.

As permitted by the Public Utilities Commission Rule 810-RICR-00-00-1-1.3(H)(3) and Rhode Island Gen. Laws § 38-2-2(4)(A), -(B), the Company is seeking confidential treatment of the GMP BCA Spreadsheet.

Attachment J

Attachment J:

Cybersecurity, Data Privacy, and Data Governance Plan

PPL Corporation
Cybersecurity, Data Privacy, and Data Governance Plan

Introduction

This **Cybersecurity, Data Privacy, and Data Governance Plan ("Plan")** provides a framework that includes a comprehensive set of principles and standards that address cybersecurity, data privacy, data governance, information classification, and enterprise security standards for PPL Corporation and its affiliates and subsidiaries ("Company").

The Plan, in conjunction with other corporate policies as identified below, has been developed to ensure the management, protection and secure availability of the Company's data and information assets. Addressing key functionalities and processes, the Plan seeks to ensure that (1) the data generated by Company and through its advanced metering functionality ("AMF")[1] is collected, managed, stored, transferred, and protected in a way that preserves customer privacy; (2) practices are consistent with cybersecurity requirements and facilitate access to further operational requirements; and (3) grid modernization and clean energy objectives are met. The Plan also seeks to support critical infrastructure and vital business functions including AMF. Additionally, the Plan addresses how the Company protects the confidentiality, integrity, and availability of all data and information, data and information assets, and data and information resources to a level that is commensurate with their value. Finally, it addresses the Company's commitment to reduce the risk of information loss by accidental or intentional modification, disclosure, or destruction.

Contents

[1] "AMF" is used generically to refer to the functionality provided by advanced meters or smart meters. Recognizing that the local references differ being 'AMF' in RIE, 'AMI' in PPL EU and 'Smart Meters' in KY, for simplicity, "AMF" is being used unilaterally throughout the document to applying equally to all jurisdictions.

- Vendor Cybersecurity Requirements Assessment
- Cybersecurity Operations
- Risk Assessment, Testing, and Quality Assurance
- Data Privacy
- Standards
- Impact on Overall AMF Security

A. Background

PPL Corporation maintains a strong commitment to cybersecurity and data privacy, continually investing in its human resources, processes and technology. The Company, in recognition of the need to maintain and enhance a defensive and in depth cybersecurity plan that seeks to prevent and mitigate ever-changing cyber risks and threats, has developed and implemented pertinent policies and standards addressing cybersecurity, data privacy, data governance, information classification, and enterprise security standards in accordance with the International Organization for Standardization ("ISO") standards. Through these policies and standards, the Company's cybersecurity, data privacy, and data governance strategy seeks to support the Company's critical infrastructure and vital business functions including AMF. This strategy ensures the confidentiality, integrity, and availability of systems and data through a process to continually evaluate all aspects of AMF data and information including review of policies, standards, and procedures, and implementation of technical controls and security measures. These objectives support the Company's goal to provide safe, affordable, reliable, and sustainable energy to our customers and superior, long-term returns to our shareowners.

PPL Corporation and its family of companies provide essential energy services to about 3.5 million customers. We provide an outstanding service experience for our customers, consistently ranking among the best utilities in the United States. As one of the largest regulated utility companies in the United States, we understand the energy we provide is vital to our customers and communities. To that end, over the past decade, PPL has invested more than $20 billion in new infrastructure and technology in our United States operations to create a smarter, more reliable and resilient energy grid for generations to come. As the energy grid evolves, so does PPL. PPL's companies are addressing new challenges head-on and are finding ways to accommodate new technologies, distributed generation and renewable power sources on our grid.

B. Plan Framework

The following corporate policies have been developed to ensure the management, protection and secure availability of the Company's data and information assets:

- Data Governance Policy
- PPL Standards of Integrity

- PPL Responsible Behavior Program
- Information Security (CP 403)
- Information Classification and Handling (CP 404)
- Electronic Information Security (CP 405)
- Records Management (CP 407)
- PPL Electric Cybersecurity Policy (CIP 001)
- PPL FERC Standards of Conduct (CO 810)
- PPL Enterprise Information Security Policy (CP 412)
- Data Security Standard ESS-04

Together these policies, lay out a comprehensive set of principles and standards for the customer and system data produced by the Company and its AMF deployment. These guiding principles are designed to ensure the data generated by the Company and through its AMF is collected, managed, stored, transferred, and protected in a way that preserves customer privacy, is consistent with cybersecurity requirements, and facilitates data access in furtherance of operational requirements, as well as grid modernization and clean energy objectives. This Plan, as outlined here, provides a structure for how AMF data and information will be governed. The Plan also discusses system data as it pertains to AMF in the context of ongoing grid modernization efforts. The policies include an explanation of how the Company provides customers with access to data and enables the sharing of that data with non-regulated power producers and other authorized third parties.

The Company has developed a comprehensive and integrated data governance framework designed to ensure compliance with privacy, cyber, and information security regulations across all jurisdictions in which it does business. The framework is meant to ensure that customers' data and information is properly protected, but also readily available to them or any third party with whom they wish to share their data. In striking this balance and committing to the secure delivery of AMF, the Company focuses on three key data security components:

- a commitment to core data-privacy principles;
- regular assessments of the Company's performance in accordance with the principles; and
- constant vigilance.

The approach is also reflected in its risk-based cybersecurity framework that tracks across people, process, and technology:

> *Setting forth policies and standards intended to ensure the Company works to common security objectives by regularly updating cyber, privacy and security guidance (including incident management and reporting) for those with legitimate business needs to access customer data; addressing privacy throughout the data lifecycle, working to prevent*

accidentalmisuse/loss/exposure of information; and ensuring cybersecurity controls are implemented, information risks are understood, andtechnologies are selected to keep pace with threats.

The applicable policies included herein provide further detail of the Company's approach to data and information privacy, and its commitment to cybersecurity, security and protection.

C. People

The Company maintains a cybersecurity focused workgroup comprised of individuals who are trained, certified, and experienced in information and cybersecurity. Investment in, and ***ongoing*** assessment of our cyber skills is vital to the success of our cybersecurity function. Our employees work with business and information technology partners to implement and monitor the necessary layers of cyber defenses. Our personnel hold and maintain several IT industry standard security certifications, and actively pursue additional relevant intelligence and training. Several team members hold federal security "SECRET" level clearances, and actively participate in security forums, peer sharing groups, vendor partnerships, industry organizations, and state and federal avenues for information and intelligence sharing. This level of engagement and skills development enables the team to keep up with emerging threats, defenses design, and evolving technologies, such as with technologies that support AMF architectures. The Company also contracts as needed with experienced cybersecurity consulting firms, and engages objective assessors to perform security skills, design, and operational assessments as may be needed, and includes evaluations of our program compared to cybersecurity frameworks. By aligning the Company's strategic planning, portfolio management, individual and collaborative expertise, process excellence and commitment to investing in cybersecurity technology, the Company is well positioned to efficiently deliver and operate AMF in a cohesive manner that provides benefits for customers and addresses the Company's operational needs.

D. Process

Our Company employees leverage our internal security policies, standards methodologies, and procedures. These internal elements are derived from security best practices from a variety of proven sources, congruent with the relevant security requirements and nature of the assets/information to be protected, such as AMF. For example, the Company's cyber security program is not only well rooted in the National Institute of Standards and Technology ("NIST") security standards, but also has benefited from ongoing assessments against other mainstream cybersecurity frameworks. Our cybersecurity team continually reviews and updates our Enterprise Security Standards to ensure congruence with NIST cybersecurity framework, and continues to look to best practice guidance for novel and effective ways to protect the company's assets from current and emerging threats.

E. Technology

Our Company has a strong commitment to investing in cybersecurity technology to support its defenses in depth. Along with the technology investments such as AMF that enable enhancements in areas such as improved reliability, customer satisfaction, communications, and mobility, the Company's cyber defenses must keep pace. With our qualified employees in place, who develop and follow strong and proven processes aligned to best practices, the functional and security technology can work together to provide secure results.

F. Purpose

When evaluating the risk and possible repercussions of a cybersecurity event, the Company will consider not only the potential impact to the flow of power to customers, but also the intended flow of data through the Company's system(s). Security and privacy recommendations will be designed to provide an acceptable level of protection for the continued confidentiality, integrity, and availability of the data that is stored, processed, and transmitted through the system, as well as the Company's continued ability to control the flow of power to customers. The likelihood that any potential adversary will attack the Company's AMF is dependent upon three general areas; desire to attack the system, the capability to conduct an attack, and the opportunity to attack. The desire to attack is based on the overall system awareness of the attacker and the perceived value of the information stored, processed, or transmitted over the Company's data paths. If a potential attacker determines that the value of the data warrants an attack, they must develop the capability to launch an attack, and to do so, they must be presented with the opportunity to launch an attack.

G. Organizational Commitment

PPL has enterprise-wide operating processes in place to ensure reliability and a robust security environment which will be used for AMF. Figure 1 identifies the relevant internal organizations and a list, albeit not exhaustive, of their responsibilities with respect to AMF cybersecurity and overall responsibility for reliability.

Responsible Business Group	Responsibilities
Please identify responsible group	• Primary responsibility for secure, reliable operation of the AMI System including security of the smart meters • Total system and security responsibility and accountability • Disaster Recovery and Business Continuity Planning • Asset Identification and Management
Human Resources/ Physical Security	Personnel: • Screening, qualification, and requalification • Background Checks • Training • Access Control • Physical Security requirements
Cybersecurity Group	• Data Loss Prevention • Anti-Malware Management • Perimeter & Remote Access Protections • Encryption • Logical Access Controls/Identity Management • Password Management • Intrusion Detection • Incident Detection • Vulnerability Scanning & Remediation • Penetration Testing/Security Risk Assessment • Secure Code Reviews • System Hardening • Distributed Denial of Service (DDoS) protections • Disaster Recovery and Business Continuity Planning • Security Education, Awareness and Training • Security Patch Management • Cybersecurity Incident Response • Vendor Security Assessment • Other focus areas identified as needed

Figure J.1. Organization Cybersecurity Responsibilities

H. Approach to Cybersecurity

To ensure cybersecurity risks are adequately addressed, the Company will utilize its project management methodology to aid in creating cybersecurity controls, processes, and procedures. This process is a risk management-based approach for identifying, quantifying, and mitigating risks throughout a project's lifecycle. This approach enables the Company to understand and manage the threats and risks in its current operations, as well as to identify potential future risks and develop appropriate mitigation plans. The way the cybersecurity and data privacy components integrate with the AMF lifecycle process is included in Figure J.2.

DEFINITION	DISCOVERY	DESIGN	DEVELOPMENT
• Establish documentation repository • IT governance approval process for definition phase	• Initial security assessment • Create functional requirements document: detail scope, specifications, use cases, management controls, personnel and training, security perimeters, incident reporting, response planning, recovery plans	• Review design w/ technology and strategy team • Manage issues and risks • Create test plans: unit, systems and stress test • Create or revise security assessment	• Finalize operations and maintenance manual • DR, backup, recovery, etc. • Create production deployment plan and operational readiness assessment: Security risk assessment, Vulnerability scanning Penetration testing, Secure code reviews • Create training plan and training materials if applicable • Create business continuity plan • Conduct pre- deployment business continuity test • Manage issues and risks

DEPLOYMENT	DEBRIEF	SUPPORT
- Manage issues and risks - Employee training - User account/access provisioning - Distribution system operator acceptance testing - Security verification testing - Security operations implemented	- Document lessons learned	- System monitoring and management - Incident response - Configuration management - System audit - Security risk assessments - Disaster recovery exercises - User access maintenance - System decommissioned /disposition: Sensitive data destruction, System disposition, Operations and policy updates

Figure J.2. PPL Project Management Methodology Process

I. Vendor Cybersecurity Requirements Assessment

AMF system equipment provided by third party vendors will be evaluated for compliance with cybersecurity requirements derived from the Company's Enterprise Security Standards and appropriate industry security standards and frameworks. This evaluation process will continue throughout the development lifecycle, and is outlined in Figure J.3 below.

Review Proposed Hardware	Hardware Recommendations
• Evaluate Hardware for Applicability to the Defined Requirements • If Applicable, Evaluate Hardware Capability for Compliance with Requirements • Identify Any Hardware Requirement Deficiencies	• Evaluate Hardware Deficiencies and Identify Possible Mitigating Factors • Rate Hardware Requirements Compliance as 'Compliant Out of the Box', 'Mitigation s Required for Compliance' or 'Non-Compliant, No Mitigations Possible' • Identify if Alternative Hardware Solutions are Needed • Develop Recommended Actions for Consideration Prior to Implementation

Figure J.3. Vendor Cybersecurity Requirements Assessment

Any changes to the hardware solutions planned will be evaluated via this process, and recommendations will be presented prior to implementation. In the event that a component cannot meet the Company's cybersecurity requirements, we will evaluate the risk and its mitigation options as part of the Company's Security Risk Assessment process.

J. Cybersecurity Operations

The project management methodology extends to operational support of the cybersecurity environment. To that end, the AMF program will implement monitoring, logging, and incident reporting. The Company plans to implement intrusion detection systems and processes to provide alarming and notification of security events. Additionally, the Company's Computer Security Incident Response Team ("CSIRT") will utilize existing tools, capabilities and procedures to provide timely response and recovery from security incidents. Upon notification that a security incident may have occurred, or is likely to occur, an alert is sent to the Executive Crisis Team ("ECT"); the ECT assesses the incident and, if necessary, assembles a CSIRT Team comprised of subject matter experts relevant to the specifics of the incident. The response team prepares an action plan, mitigates the security incident, and assembles documentation in accordance with the Company incident response procedures. These procedures will be reviewed and updated, if necessary, during the AMF cybersecurity design process. The Company currently has in place policies and procedures for managing user access, performing system audits, reviewing system logs, etc. to maintain cybersecurity vigilance. These policies and procedures will be augmented, if need be, to address any new or unique risks or issues associated with AMF. In addition, updates and patches to infrastructure devices and systems will be managed using the existing Configuration and Change Management Standard. This standard requires that upgrades, both major and minor, must include a security risk assessment prior to operational implementation.

The Company has in place both Disaster Recovery ("DR") and Business Continuity ("BC") plans that are regularly tested by means of DR and BC drills. These plans will be updated to encompass the AMF systems, and DR and BC drills will be conducted as part of operational readiness testing to verify plan effectiveness.

K. Risk Assessment, Testing, and Quality Assurance

AMF will create a Risks Register document, and any cybersecurity or data privacy related risks will be entered and managed accordingly. Test plans will be developed and executed to ensure that cybersecurity functions operate as designed. Figure J.4 below depicts the Company's approach to system security testing.

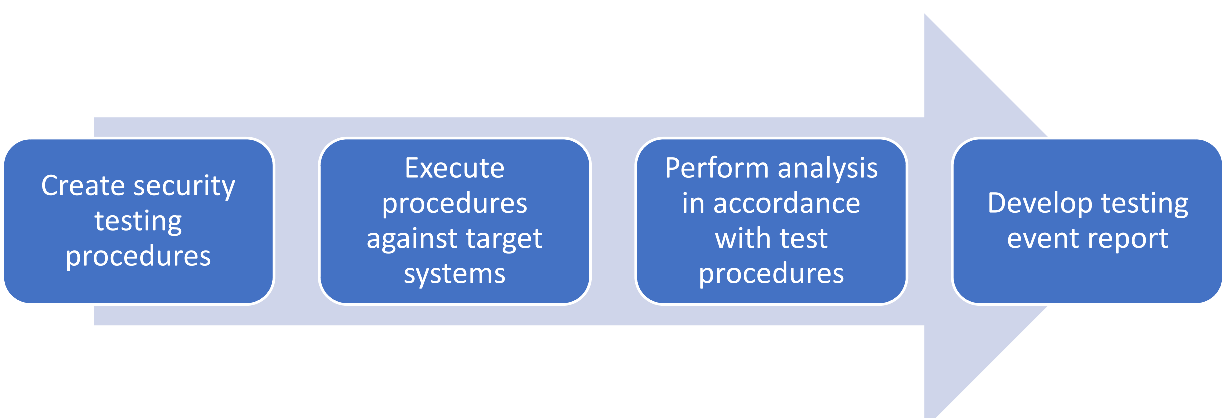


Figure J.4. System Security Testing

The cybersecurity team will be responsible for identifying and mitigating security risks and ensuring that the fielded systems meet the requirements and configuration as prescribed in the Company's Enterprise Security Standards, and include the following activities:

Security RiskAssessments
The Security Risk Assessment ("SRA") is a review that provides a baseline for the development of risk mitigation actions needed to protect the utility's systems and environments. It is conducted using a well-defined set of information security standards, guidelines, and industry best-practices. The SRA activities will include:
1) System characterization (both operational and technical), 2) Threat identification, 3) Vulnerability identification, and 4) Risk Determination/Valuation.

Using the guidelines provided by Federal Information Processing Standards ("FIPS") and NIST among others, the Security Risk Assessment will determine the potential impact of threats and vulnerabilities to the Confidentiality, Integrity and Availability ("CIA") of AMF's data and systems. This impact determination, combined with an assessment of threat probability, will form the basis for risk-weighted mitigation planning.

Vulnerability Scans
Vulnerability scans are conducted on the operational system, prior to deployment and post-deployment, to ensure the system adheres to the cybersecurity design. This quality assurance check is conducted using automated tools and manual scanning to verify configuration items such as: firewall rules, port configurations, password structure and complexity, user authentication and access permissions, etc.

Penetration Testing
Penetration testing is the best indicator of real-world vulnerability to cyber-attacks, both internal and external. Conducted by objective, experienced and knowledgeable "Certified Ethical Hackers," this activity determines the degree to which the systems are vulnerable to a variety of cyber-attacks. The team will conduct a series of targeted attacks from the smart meters to the AMF systems and document the gaps and vulnerabilities discovered. These gaps and vulnerabilities will be managed and/or mitigated.

L. Data Privacy

One of the first steps of the initial security assessment is to determine the type of data and information that requires protection so that the appropriate security controls are planned in advance. For AMF, the "Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and the Smart Grid" recommendations will be followed and conduct a privacy impact assessment ("PIA") before any deployment. The PIA will help the project team with the following:

Identifying and managing privacy risks: Conducting an exercise to identify potential privacy risks early in the project demonstrates good governance and business practice.

Meeting legal requirements: Conducting the assessment provides the opportunity to ensure that any privacy risks are identified early, and thereby implementing the appropriate controls that will allow for ensuring the implementation adheres to legal requirements. This also applies when engaging a third party, where the data owner is responsible for ensuring the appropriate controls are in place to protect personal data.

M. Standards

As noted, the AMF Project will leverage emerging interoperability and security standards, including, but not exclusive to those developed by the NIST. Throughout the AMF Project lifecycle, security requirements, processes and procedures will leverage the following standards:

Security Requirements Creation	NIST SP 800-53 *" Recommended Security Controls for Federal Information Systems and Organizations"*
Security Risk Assessment Methodology	NIST SP 800-30 *"Risk Management Guide for Information Technology Systems" ,* NIST SP 800-60 *" Guide for Mapping Types of Information and Information Systems to Security Categories" ,* and FIPS 199 *" Standards for Security Categorization of Federal Information and Information Systems"*
Vulnerability Identification	NISTIR 7628 *"Guidelines for Smart Grid Cybersecurity: Vol. 2, Privacy and Smart Grid'*
Security Testing Methodology	NIST SP 800-115 *"Technical Guide to Information Security Testing and Assessment"*

N. Impact on Overall AMF Security

Protection of AMF is accomplished via multiple layers of network, personnel, and physical security barriers. If compromises to the system were to occur, the location of that compromise would determine the impact on the overall AMF security. While there are numerous endpoint devices in the AMF network, compromise of one device would have a lower overall impact than a compromise of the AMF Systems. These levels of compromise are represented in Figure J.5, with red representing the highest potential impact.

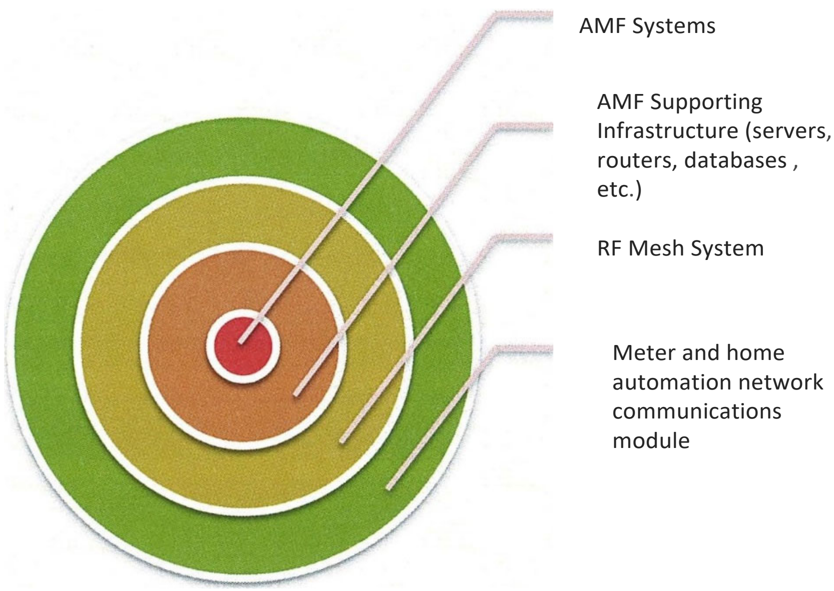


Figure J.5. Potential Impact to Overall Grid Security

AMF will be implemented with cybersecurity and data privacy as a cornerstone. The increased scrutiny of the AMF systems and network, the interfaces with new smart devices, and reviews and updates to existing policies, procedures, and operational concepts is expected to maintain the overall security posture of AMF.

Attachment K

Attachment K:

Rhode Island Energy Grid Modernization Loss Study

Purpose

In the Grid Modernization Plan (GMP analysis), distribution system models with the necessary electric vehicle load, electric heat pump load and DG to meet state-wide emission reduction goals were simulated to assess solutions for the No Grid Modernization alternative and the Grid Modernization alternative required to prevent adverse loading and voltage issues. The No Grid Modernization alternative solutions are based on traditional wire infrastructure that expand system capacity through the construction of new feeders, sub-transmission lines and substations to accommodate the increased load and DG. The Grid Modernization alternative solutions leverage the proposed grid modernization capabilities from the Foundational Investments that enable time-of-use load shifting, granular DG curtailment, battery storage control, and volt-var inverter control to defer some of the No Grid Modernization infrastructure cost while still accommodating the increased load and DG.

In addition to the infrastructure cost deferrals from the grid modernization solutions, the distribution and transmission losses from both alternatives must also be compared to factor into the claimed benefits of the proposed grid modernization implementation. To make this comparison and to evaluate the effect DG has on losses, this study will assess and compare annual energy losses of the Central RI East distribution planning area with the necessary load and DG to meet state-wide emission reduction goals under the following cases:

1. No Fixes Case – The case without any solutions that address the adverse loading and voltage conditions, also referred to as the no solutions case
2. No Fixes DG Off Case – The case without any solutions that address the adverse loading and voltage conditions and with all DG disabled, also referred to as the no solutions case with DG disabled case
3. Non-GMP Case – The case with non-GMP solutions that address the adverse loading and voltage conditions
4. GMP Case – The case with GMP solutions that address the adverse loading and voltage conditions
5. GMP DG Off Case – The case with GMP solutions that address the adverse loading and voltage conditions and with all DG disabled

Background

Distribution and transmission system losses in lines, cables, transformers, and other equipment carrying load make up the fraction of generated energy that does not supply customer loads. Since distribution and transmission losses don't supply customer loads, they are accounted as cost without benefit. Typical distribution and transmission system losses are in the range of 3% to 6% of the supplied energy from generators. To minimize the cost of lost generated energy, the distribution and transmission system losses must be kept as low as possible.

Most distribution and transmission losses come from conductor and equipment resistive losses, which are a function of load current squared and resistance of the conductors and equipment carrying load current. Conductor resistance is a function of conductor length, cross sectional area and resistivity. The highest distribution system losses exist in feeders and sub-transmission lines that carry more load current over greater distances. Expanding existing system capacity to relieve lossy feeders and sub-transmission lines is an effective way to reduce overall distribution system losses, but it comes at the cost of capital expense.

Distributed generation (DG) can also reduce distribution and transmission losses if sized and located accordingly. DG can provide energy closer to customer loads, which reduces both the length of the load carrying conductors and the load current that is supplied from the transmission system. In some cases when DG is greater than all the gross customer loads on its distribution network, DG power back feeds into the transmission system. Distribution losses can increase since high current flow that back feeds into the transmission system can be larger in magnitude than forward current flow during periods of peak load. In addition, power from DG back feed supplies customers in remote distribution networks. Therefore, additional distribution losses in those remote distribution networks exist during these periods of excessive DG.

Study Methods

The study method was developed to compare distribution and transmission losses from five alternative cases for a representative subset of the Rhode Island Energy distribution system to ensure that the differences in percent loss between the cases accurately represent percent loss differences at the state-wide level.

The Company first established the study assumptions, then determined the software and data requirements.

Study Assumptions:

- 15kV Class Feeders - This is Rhode Island Energy's most common feeder class and the feeder class most interconnected to by new load and DG.

- 25kV Class Sub-Transmission Lines - This is Rhode Island Energy's most common sub-transmission class and the sub-transmission class most interconnected to by new load and DG.
- Secondary Losses - Each feeder's and sub-transmission line's secondary losses were calculated assuming each power distribution service transformer's loss at its peak power is 0.4kW and that each secondary service line is a 160-foot length of 4/0 triplex line.
- Transmission Losses – Each feeder's and sub-transmission line's transmission losses were assumed to be 3% of the power through their substation breakers.
- Remote Distribution Losses – Each feeder's and sub-transmission line's remote distribution losses were assumed to be 3% of the power through their substation breakers when their DG back fed into the transmission system.

Software and Data Requirements:

- CYME Software with Load Flow with Profiles module - this modeling software and analysis module are used by Rhode Island Energy for all 8760 analyses.
- 35 Central RI East Feeder Models – the feeder models, which included the necessary load and DG to meet state-wide emission reduction goals, were selected for their robustness during load flow with profiles analysis and were used to collect the loss and load data necessary for the analysis.
- 4 Central RI East Sub-Transmission Line Models – the sub-transmission line models, which included the necessary load and DG to meet state-wide emission reduction goals, were selected for their robustness during load flow with profiles analysis and were used to collect the loss and load data necessary for the analysis.
- State-wide Emission Reduction Goals – Electric vehicle loads, electric heat pump loads, PV generation and wind generation, all set at unity power factor, were distributed in the models in quantities that meet state-wide emission reduction goals.
- Rhode Island Energy's load and generation profiles – these projected factors scale electric vehicle load, electric heat pump load, economic load, PV generation and wind generation independently for each hour to represent the varying load to generation ratios that will directly impact how the losses vary over the year.

The load flow with profiles analysis was run with the selected feeders and sub-transmission lines to capture a time series of load flow data in 3-hour intervals. The profiles used in the analysis scaled the feeders' and sub-transmission lines' electric vehicle loads, electric heat pump loads, economic loads, PV generation and wind generation independently at every 3-hour increment. These profile scaling factors are used to accurately represent the projected variation of the load to generation ratios that directly impact how the losses vary over the year. Downstream primary losses and through power were monitored at each feeder's and sub-transmission line's substation breaker and recorded every 3-hour increment to use in the following analysis.

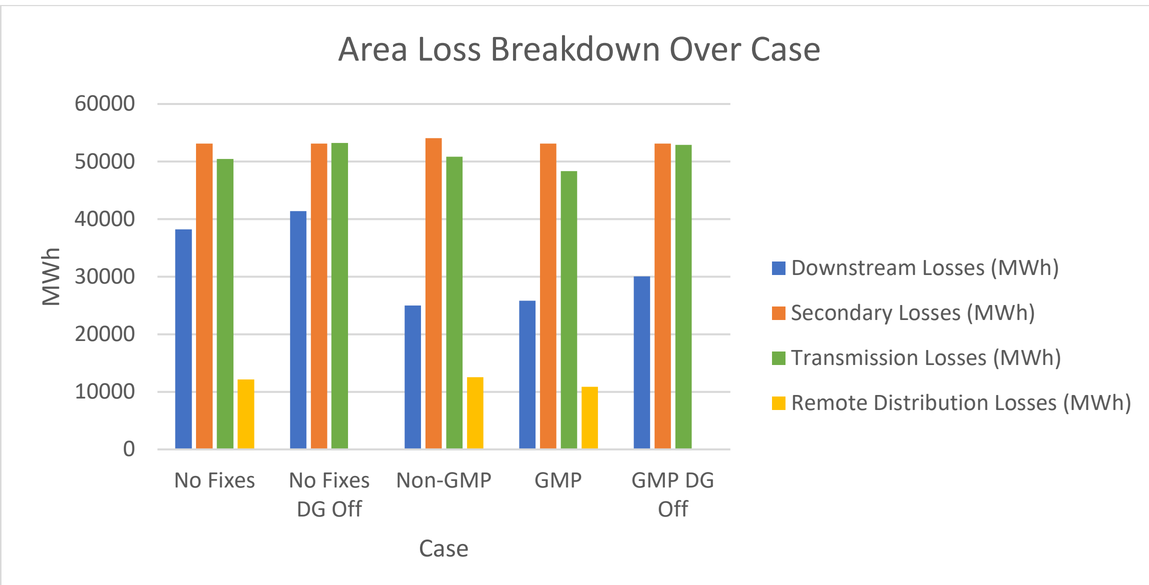
Supporting data was also derived outside of CYME. Each feeder's and sub-transmission line's downstream gross load, secondary losses, transmission losses and remote distribution losses were derived for each three-hour interval across the year. In the following analysis, downstream gross load refers to the total load consumed by customers connected downstream of each feeder's and sub-transmission line's substation breaker. Secondary losses refer to the losses in all the power distribution service transformers and secondary service lines used to supply downstream gross load. Transmission losses refer to the losses in the transmission system that supplies each feeder and sub-transmission line. Remote distribution losses refer to the losses in the remote distribution networks with customers supplied by the DG power from each feeder and sub-transmission line back fed into the transmission system.

The monitored and derived data was then used to derive total loss and total gross load. In the following analysis, the total loss for each feeder and sub-transmission line was calculated as the sum of downstream primary losses, secondary losses, transmission losses, and remote distribution losses. The total gross load for each feeder and sub-transmission line was calculated as the downstream gross load plus the substation breaker through power when DG power back fed into the transmission system. This DG back feed power, referred to in the analysis as back feed gross load, is factored into the total gross load to account for the additional customers in remote distribution networks supplied by each feeder's and sub-transmission line's DG power back fed into the transmission system.

Annual loss and load energy for each feeder and sub-transmission was derived by summing all their total loss power values and total gross load power values across the year and multiplying by the 3-hour time interval used in the load flow with profile analysis. The loss and load energy were then summed across all the feeders and sub-transmission lines to get total loss and load energy of the entire study area. These results were then analyzed, compared, and organized in the format shared in the analysis results section below.

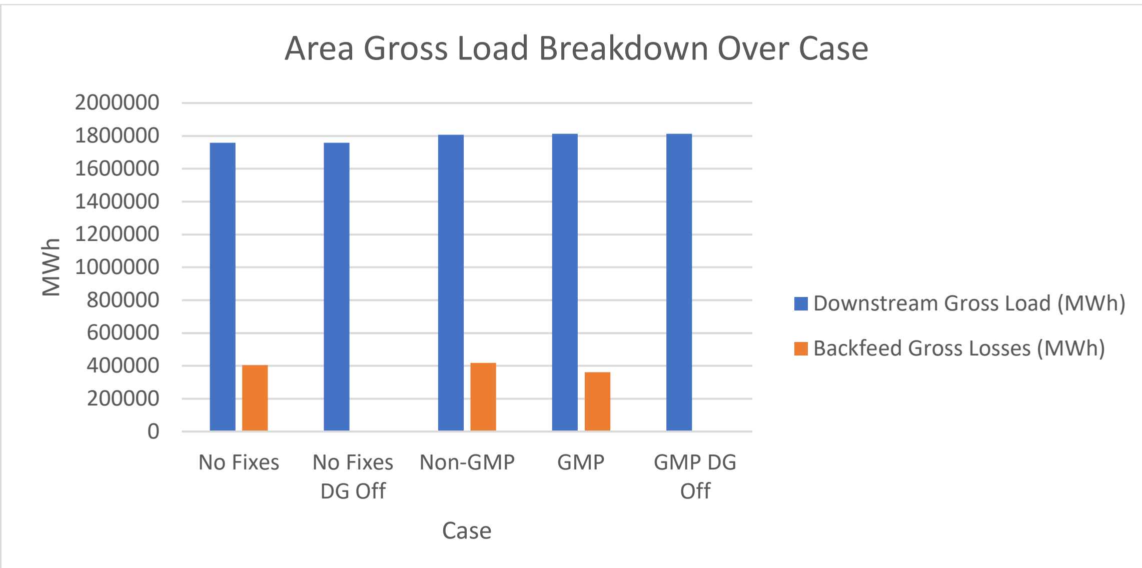
Analysis Results

For each case studied, all the sources of loss were captured and compared to better understand each case's loss breakdown. Out of all the sources of loss contributing to total losses, the secondary losses contributed the most, with annual energy that exceeded 53,000 MWh (megawatt hours) in all cases. Since the downstream gross customer load and secondary distribution equipment does not vary significantly between the cases, the secondary losses are constant over all the cases. The next highest loss contribution was from the transmission losses, which were greater than 48,000 MWh for all the cases. The highest transmission losses, at about 53,000 MWh, come from the two cases with DG disabled because all the downstream customer loads are exclusively supplied by the transmission system without support from DG. Varying from 25,000 to 41,000 MWh, downstream primary losses are the third highest contributor. The non-GMP and GMP solutions that eliminate overloading issues reduce these downstream losses compared to the cases without solutions. The presence of DG in the cases with DG enabled also reduces the downstream primary losses compared to the cases with DG disabled since it relieves the conductors leaving the substation from carrying the entire gross load current and shortens the distance between power generation and load. Finally, the remote distribution losses are the smallest, less than 13,000MWh. These losses only exist when there is back feed into the transmission system due to high DG. Remote distribution losses do not exist in the cases where DG is disabled. Below is a chart and table showing the breakdown of the area's energy losses for the five studied cases.



	No Fixes	No Fixes DG Off	Non-GMP	GMP	GMP DG Off
Downstream Losses (MWh)	38235	41414	25018	25835	30072
Secondary Losses (MWh)	53100	53100	54072	53113	53113
Transmission Losses (MWh)	50465	53237	50865	48317	52921
Remote Distribution Losses (MWh)	12151	0	12539	10848	0

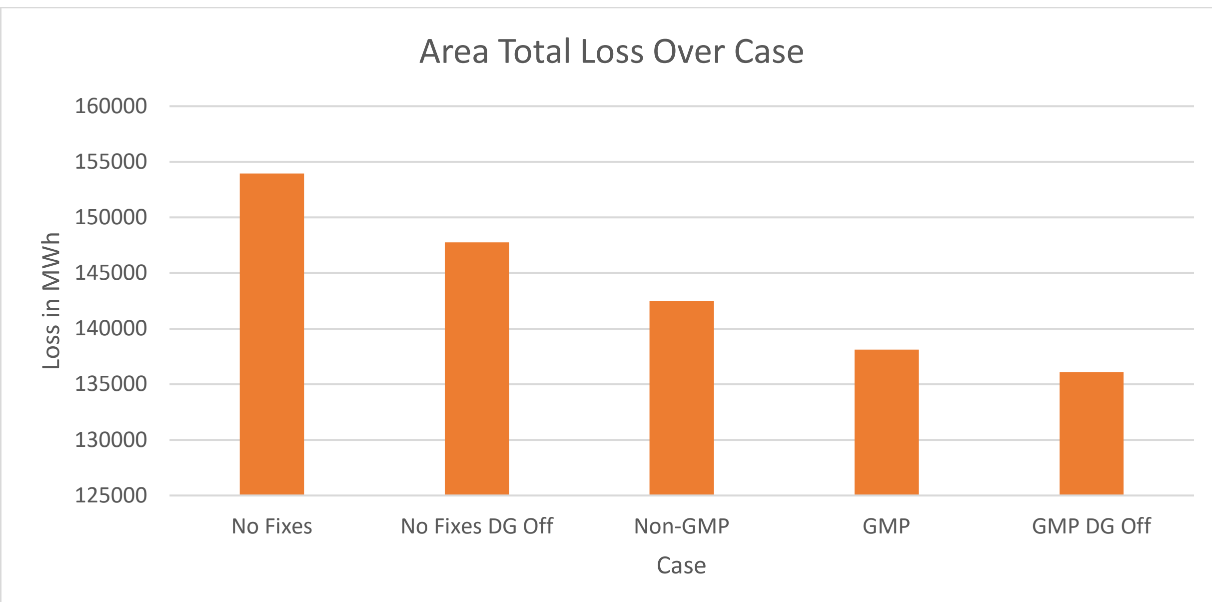
For each case, the two sources of gross load were captured and compared. Most of the gross load came from the downstream gross customer load. The downstream gross load was constant over the five cases at about 1,800,000 MWh. The variation of total gross load between cases was mostly due to the contributions of the back feed gross load. As explained earlier, the back feed gross load corresponds to the customer load supplied in remote distribution networks when there is an excess of DG on the feeders and sub-transmission lines that back feeds into the transmission system. This gross load contribution only existed in the three cases with DG enabled. It was roughly 400,000 MWh in the cases with no solutions and non-GMP solutions. The case with GMP solutions was reduced to 360,000MWh due to the granular DG curtailment of the proposed GMP implementation. Below is a chart and table showing the breakdown of the area's gross load energy for the five studied cases.



	No Fixes	No Fixes DG Off	Non-GMP	GMP	GMP DG Off
Downstream Gross Load (MWh)	1758421	1758421	1807940	1812767	1812767
Backfeed Gross Losses (MWh)	405034	0	417972	361600	0

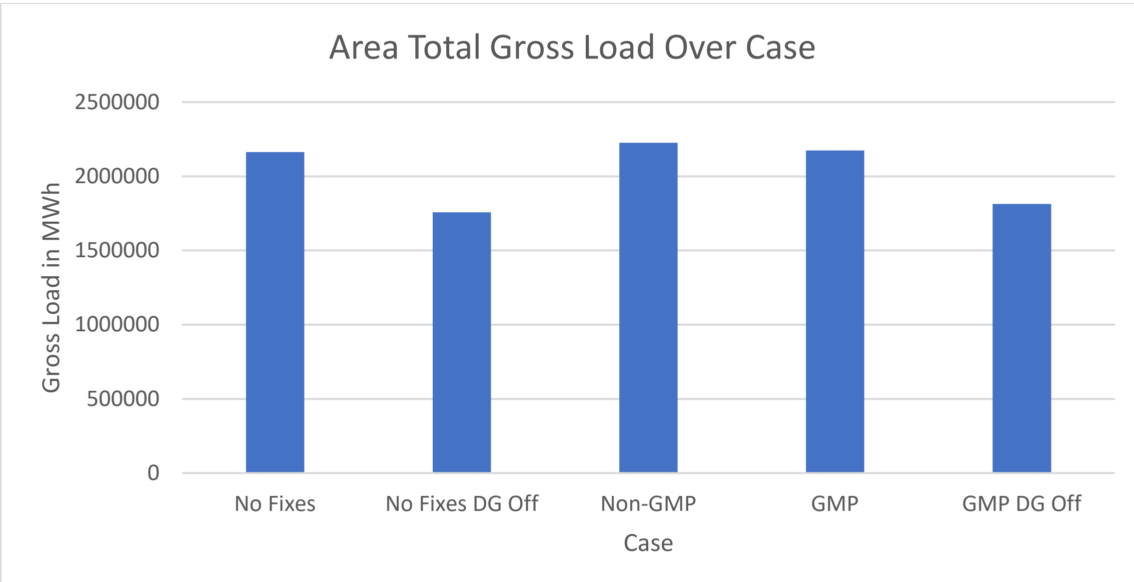
Summing all the sources of losses to derive the total loss and summing the downstream gross load and back feed gross load to derive total gross load combines all these considerations to compare each case's overall loss and gross load. Using these quantities, percent loss can be derived by taking each case's total loss as a percent of the total energy consumed by both losses and gross load.

Comparing the area total losses of the five cases shows the highest losses exist in the two cases with no solutions. Without the non-GMP or GMP solutions addressing the overloads that occur with the load and DG necessary to meet the State's emission reduction goals, the downstream primary distribution losses are higher for the cases with no solutions. The no solutions case with DG enabled has the highest losses because the DG power back feeding into the transmission system contributes 12,000 MWh of remote distribution losses to its total losses, 154,000 MWh. As explained in the breakdown, the non-GMP and GMP solutions that address overloads keep the downstream primary losses lower for the non-GMP and GMP cases. This makes their total loss lower than the cases without solutions. When comparing the cases with non-GMP and GMP solutions, the case with non-GMP solutions shows higher overall losses, at 142,000 MWh. The granular DG curtailment implemented in the case with GMP solutions reduces losses from excessive DG that back feeds into the transmission system and remote distribution networks. Disabling the DG in the GMP solutions case reduces these remote distribution losses to zero. This makes the case with GMP solutions and DG disabled the case with the lowest overall losses, at 136,000 MWh. Below is a chart and table showing the area's total loss for the five studied cases.



	No Fixes	No Fixes DG Off	Non-GMP	GMP	GMP DG Off
Losses (MWh)	153952	147752	142493	138113	136106

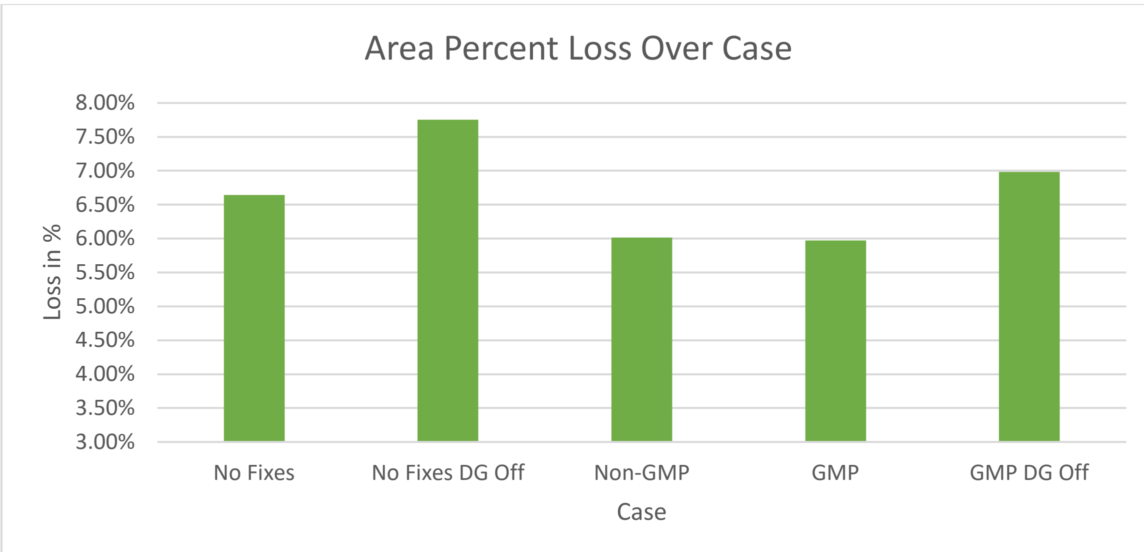
Comparing the area's total gross load over the cases shows that the three cases with DG enabled have higher overall gross loads, all above 2,170,000 MWh, than the two cases with DG disabled, both under 1,820,000 MWh. As shown in the gross load breakdown, this difference is from the back feed gross load contribution that comes from excessive DG back feeding into the transmission system and supplying customer loads in remote distribution networks. Other than the difference from back feed gross load contribution, the area total gross load does not vary greatly over the cases. Below is a chart and table showing the area's total gross load over the five studied areas.



	No Fixes	No Fixes DG Off	Non-GMP	GMP	GMP DG Off
Gross Load (MWh)	2163455	1758421	2225912	2174367	1812767

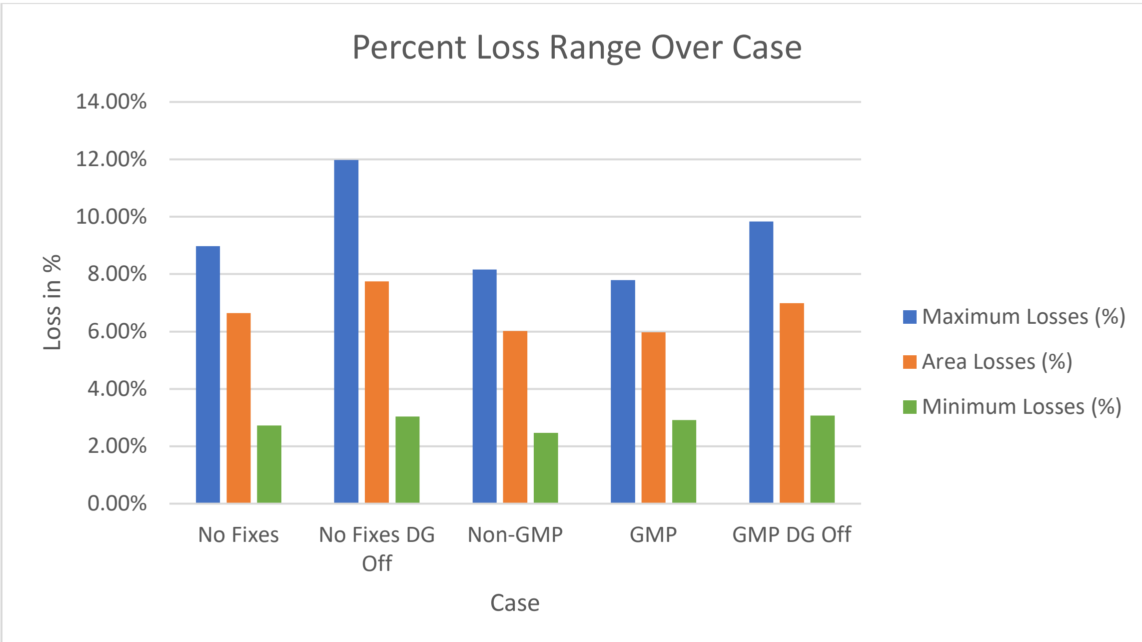
It is important to evaluate the loss energy as a percentage of the total energy consumed by losses and gross customer loads. It provides a common reference between the cases when comparing losses since it factors in the gross customer loads served. Percent loss is the rate of energy loss per energy generated to serve customer loads.

Comparing the percent loss of the five cases shows that while the energy losses are lower in the cases with DG disabled, the percent loss is higher by about 1% than the cases with DG enabled. This is because without DG, there is no back feed that supplies customer loads in remote distribution networks contributing to total gross load. For the three cases with DG enabled, the comparison of percent loss is closer to the energy loss comparison since those three cases serve similar total gross customer load. However, the DG curtailment in the case with GMP solutions cause a reduction in both total loss and total gross load with respect to the non-GMP solutions case, making its percent loss, 5.97%, very close to the non-GMP case, 6.02%. Below is a chart and table that compares the percent loss over the five studied cases.



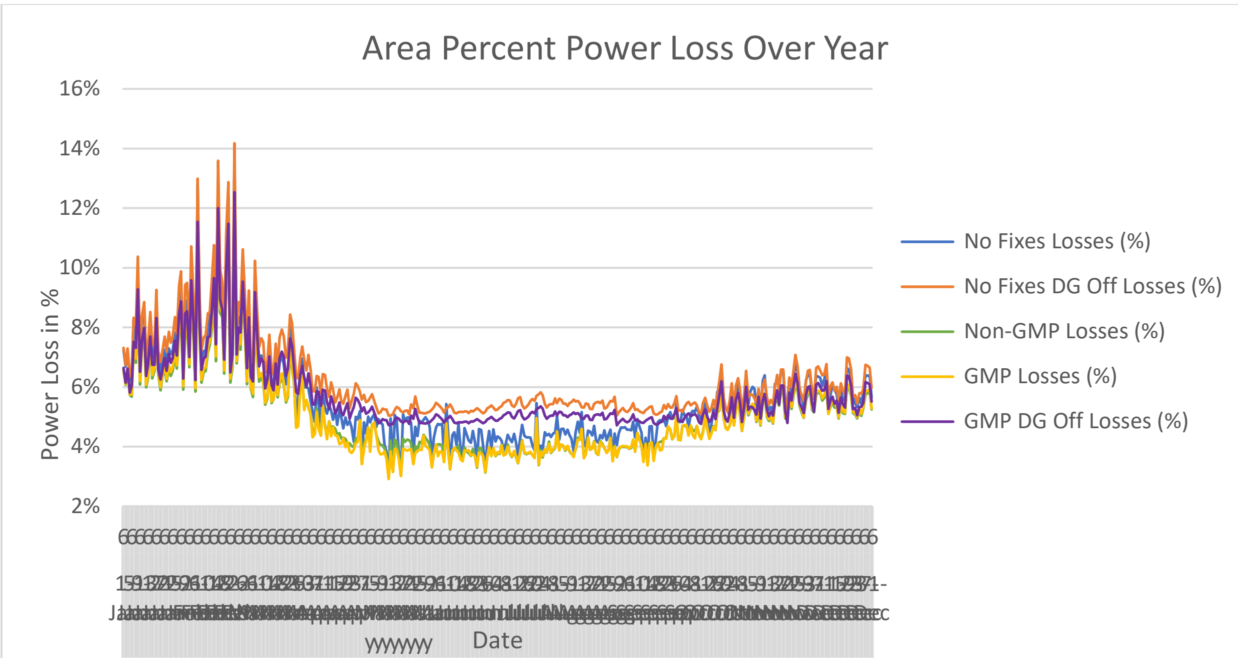
	No Fixes	No Fixes DG Off	Non-GMP	GMP	GMP DG Off
Losses (%)	6.64%	7.75%	6.02%	5.97%	6.98%

To get the area loss and gross load data, all the area feeders' and sub-transmission lines' loss and gross load data was collected and summed together. This feeder and sub-transmission line data can be further analyzed and compared across the cases. Since all the feeders' and sub-transmission lines' percent losses were derived for each case, the maximum and minimum percent loss for each case can be compared. Below is chart and table showing the maximum and minimum percent losses for the five cases studied.

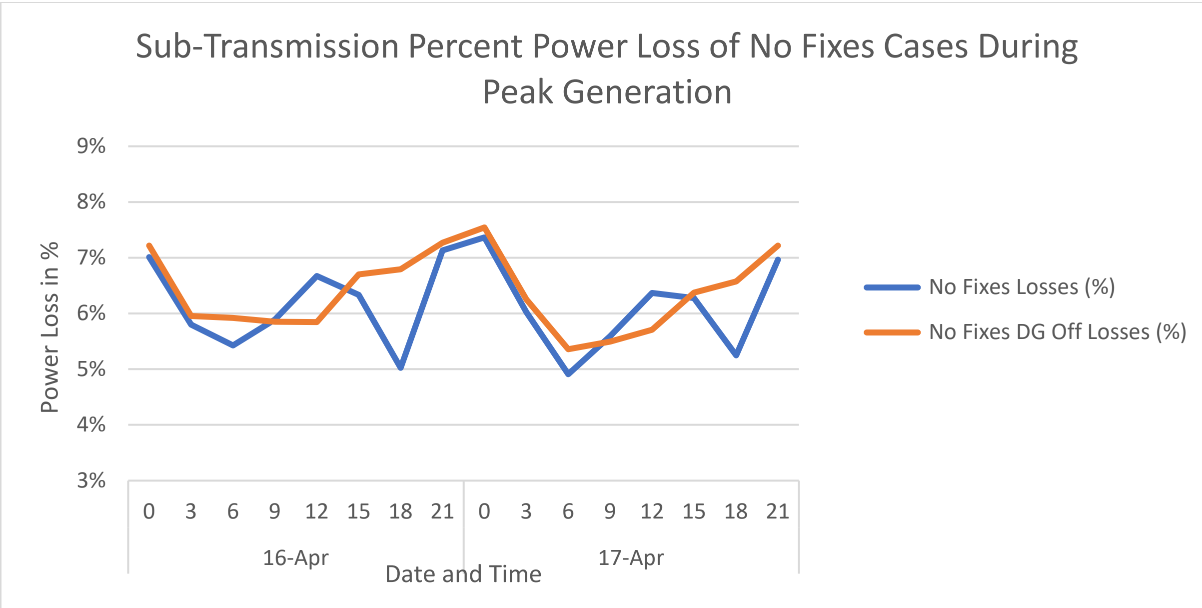


	No Fixes	No Fixes DG Off	Non-GMP	GMP	GMP DG Off
Maximum Losses (%)	8.98%	11.97%	8.17%	7.79%	9.84%
Area Losses (%)	6.64%	7.75%	6.02%	5.97%	6.98%
Minimum Losses (%)	2.73%	3.03%	2.47%	2.92%	3.07%

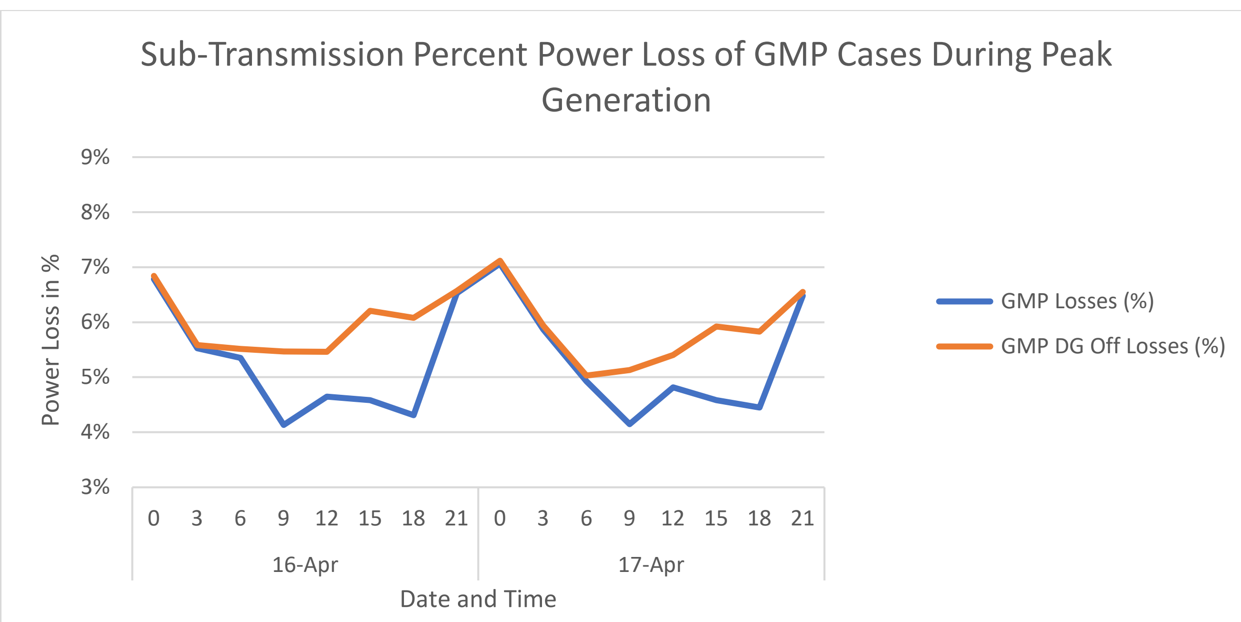
To derive the area loss and gross load data in units of energy, the loss and gross load data needed to be collected in units of power at 3-hour intervals over the year. Since each 3-hour interval's loss and gross load power data was captured, the loss and gross load power can be evaluated over the year. From the power data, the highest percent loss exists when the gross load peaks in February due to heat pump usage. 6PM is generally when the daily gross load peaks. Below is a chart showing area percent loss at 6PM each day of the year for the five studied cases.



Looking closer at a subset of the power data across the year, an anomaly was identified. During peak DG generation, the no solutions case with the DG enabled can yield higher percent loss than the no solutions case with the DG disabled. This is because the reverse power flow is so large in magnitude that the conductors exiting the substations become heavily loaded resulting in higher losses. This condition is evident when analyzing the area's sub-transmission system, which has the highest concentration of DG to meet the state's emission reduction goals. On peak generation days, April 16th and 17th, the no solutions case with DG enabled has higher losses than the no solutions case with DG disabled between the hours of 9AM to 2PM. Below is a chart showing the area's sub-transmission system's percent loss during the year's peak generation days for the no solution cases with and without DG enabled.



During this same peak generation period, the granular DG curtailment in the GMP solutions prevents that increased loss in the case with DG enabled such that its percent loss remains under the GMP solutions case with DG disabled. Below is a chart showing the area's sub-transmission system's percent loss during the year's peak generation days for the GMP solutions cases with and without DG enabled.



Conclusion

From the analysis above, it can be concluded that DG reduces percent loss by about 1% since the power it supplies is more local to customer loads than the power supplied through the transmission system. This shortens the distance the customer load current needs to travel on the distribution feeders and sub-transmission lines and reduces the power required from the transmission system. This was apparent when observing the DG enabled cases' lower downstream primary distribution losses and the lower transmission losses in the loss breakdown. Contrary to this result, the cases with DG have higher remote distribution losses. These losses exist when DG exceeds its feeder's or sub-transmission line's gross load such that the DG back feeds into the transmission system and supplies customer loads in remote distribution networks. However, this occurrence of excessive DG also increases the back feed gross load, which contributes to the total gross load of the cases with DG enabled. This back feed gross load contribution drives the percent loss of the cases with DG enabled to be lower overall than the cases with DG disabled.

For purposes of discussion, percent loss of the no solution cases with and without DG were plotted on peak generation days to show that DG can increase percent losses for subsets of the system during peak generation hours between 9AM to 2PM. The GMP solutions cases with and without DG were also plotted during the same peak generation period to show that the granular DG curtailment implemented in the GMP proposal will reduce back feed and the associated losses. This reduced loss prevented the percent loss of the GMP solutions case with DG enabled from exceeding the GMP solution case with DG disabled.

Another conclusion drawn from the analysis is that the cases with non-GMP and GMP solutions had percent loss 0.6% lower than the cases with no solutions. The infrastructure and solutions in the non-GMP and GMP cases that addressed all adverse loading issues from the increased load and DG required to meet state-wide emission reduction goals also reduced downstream primary losses with respect to the cases with no solutions. With the secondary losses, transmission losses, remote distribution losses and gross load relatively constant between the cases with no solutions and non-GMP solutions, the reduction in the downstream primary losses made the percent loss lower for the case with non-GMP solutions. The case with GMP solutions included DG curtailment that reduced transmission losses, remote distribution losses and gross load in comparison to the case with non-GMP solutions. This reduction in both total losses and total gross load ended up making the percent loss of both the cases with non-GMP and GMP solutions around 6%.

Attachment L

Attachment L:
Impact of Distributed Generation and Grid Modernization on Volt-Var Optimization Systems

Purpose

The purpose of this review is to explore the potential impacts and the magnitude of the impacts that distributed generation ("DG") can have on volt-var optimization ("VVO") systems. Distributed generators will typically increase the voltage on feeders, especially during periods of light load. This is contrary to the goal of VVO systems, which attempt to lower voltage during all hours to reduce energy consumption. This study will evaluate such voltage interactions on a real-world test circuit to determine when and to what extend DG can impact VVO systems. This review will also explore how grid modernization concepts can be used to mitigate the DG impacts.

This analysis will aim to demonstrate base VVO benefits, then show how DG sites can negatively impact these benefits. Lastly, by utilizing grid modernization solutions such as inverter volt-var control, this analysis will show that VVO benefits can be regained even with a high penetration of DG.

Background

ANSI C84.1 is the national standard that defines the allowable utility voltage range for electric services. Range A of ANSI C84.1 mandates that electric service voltage must be in the range of 114 V – 126 V. On a typical radial distribution feeder, voltage is highest at the substation (source). Voltage gradually drops as you move further away from the source as current flowing through the feeder line impedance creates a voltage drop (V = I*R). Traditionally, the goal was to keep voltages in the upper portion of ANSI Range A (120 V – 126 V) to counteract voltage drop. In order to achieve this, devices such as voltage regulators, capacitor banks, and load tap changers are used to regulate voltage.

VVO is a scheme to optimize voltage and reactive power flows on a distribution feeder, similar to Conservation Voltage Reduction ("CVR"). VVO aims to keep voltages in the lower half of ANSI Range A (114 V – 120 V) while ensuring all Customer service voltages do not drop below or exceed the allowable 114 V – 126 V range. Experience has shown that reducing overall voltage and employing a VVO scheme leads to annual demand reduction and energy savings, typically around 3%.

A VVO scheme utilizes supervisory control and data acquisition ("SCADA") devices that were mentioned above (capacitor banks, voltage regulators, load tap changers). These devices work in conjunction to keep voltage as low as possible to maximize demand and energy savings to benefit all customers. Additionally, the use of SCADA operated capacitor banks with advanced controllers can reduce VAR flow on feeders. This helps to reduce losses as a reduction in VAR flow will correspond to a reduction in line current and a more efficient system (higher power factor).

Rhode Island Energy has reviewed numerous DG interconnection studies which have evaluated the voltage rise caused by the generators. Often the interconnections studies recommend voltage mitigating solutions, such as advanced capacitors and advanced regulator controls. These solutions could be used within a VVO system, but a study to assess the impact of a specific DG on an existing or planned VVO system is not performed during an interconnection study nor does the Company recommend doing so. Instead, the Company recognizes the existing programs need to account for the changing distribution system.

Grid modernization functionalities such as inverter volt-var control and DER Monitor/Manage efforts are intended to provide real-time voltage control to meet the fundamental ANSI voltage guidelines. However, these same technologies would be used to refine existing and planned VVO systems to maximize benefits.

As highlighted by the various topics above, a study is needed to combine the programs and technologies to ensure the most cost effective and most beneficial path is chosen.

Study Methods

The study method was developed to demonstrate the benefits of the current VVO solution and the corresponding impacts of DG on a representative subset of the Rhode Island Energy distribution system. Furthermore, the analysis considered the proposed suite of grid modernization solutions to determine whether benefits would be regained with a VVO model inclusive of inverter controls.

Study Assumptions

- 15kV Class Feeder - This is Rhode Island Energy's most common feeder class and the best candidate for a VVO scheme as the vast majority of residential and commercial customers are served by a feeder of this voltage class. All of Rhode Island Energy's current VVO schemes are on 15kV class feeders.
- The Tiverton 33F4, 12.47 kV (nominal) feeder was chosen as a representative feeder for this analysis. The Tiverton 33F4 serves approximately 3,400 residential and commercial customers in the towns of Tiverton and Little Compton.

Software and Data Requirements

- CYME Software with Load Flow with Profiles module - this is the modeling analysis used by Rhode Island Energy for all 8760-hour per-year analyses. This VVO analysis will utilize 8760-hour analysis to collect data for one (1) year.
- Rhode Island Energy's residential and commercial load and generation profiles – the projected factors scale economic load and PV generation independently for each hour over one (1) year.

Analysis Steps

Load flow with profiles 8760-hour analysis was run on the Tiverton 33F4 feeder using Rhode Island Energy load and generation profiles in three-hour increments. Base peak loading in the model, which remained constant, was defined with the recorded 2021 peak loads. Rhode Island Energy 2030 load profiles were used to vary residential and commercial load throughout the analysis year. Voltage and through power was monitored at the feeder beginning, middle, and end points. For each step, total energy supplied by the 33F4 feeder was calculated for the year. For steps including DG, energy supplied by DG sites was gathered through separate monitoring points and manually added back in to correctly calculate the total feeder energy for the year.

- Steps 1 & 2: Analysis will compare energy savings on the Tiverton 33F4 from the current system to a VVO enabled system.
- Step 3: DG sites will then be included in the analysis to show the negative impact to energy savings. Approximately 9.5 MW of DG was included in the analysis.
- Step 4: DG sites will utilize grid modernization functionalities as described previously to regain energy benefits from VVO.

Analysis Results

Note: These results are for demonstration purposes only and are not an actual representation of energy savings.

Steps 1 & 2: Comparison of the current system to a VVO enabled system

For this step, an 8760-hour analysis was run on the Tiverton 33F4 feeder to model the current state (step 1). Capacitor banks were modeled using existing controls (i.e., time clock). Then, 8760-hour analysis was re-run on the 33F4 feeder with advanced capacitor and regulator controls (i.e., three-phase voltage monitoring) to enable VVO and keep voltages in the lower half of ANSI Range A (114 V – 120 V) (step 2). Step 2 represents the recently installed VVO systems evaluated with limited DG.

The energy savings in megawatt-hours (MWh) from VVO are shown below in **Figure 1.** Over the entire analysis year, enabling VVO on the Tiverton 33F4 feeder reduced total annual energy from 35,864 MWh to 33,996 MWh, corresponding to annual energy savings of 5.2%.[1][2]

Figure 1

Step 1 - Current State		
Feeder	Total MWh	
33F4	35,864	
Step 2- VVO Enabled Feeder		% Savings from Step 1
Feeder	Total MWh	
33F4	33,996	5.2%

Step 3: VVO enabled system with the addition of DG

For this step, 8760-hour analysis was run on the VVO enabled 33F4 feeder with the addition of approximately 9.5 MW of DG (step 3). As described above, DG sites will raise feeder voltage especially during high-generation, light-load periods of the year.

[1] No precision should be assumed from the reported numbers. The values are derived directly from CYME exports and subsequent calculations.
[2] This analysis shows over 5% savings for VVO systems. While in certain actual cases savings approximating 5% can occur, typical VVO saving is approximately 3% on cases with low DG levels.

Total energy was once again calculated for the year and the results are shown below in **Figure 2.** Over the entire analysis year, adding DG to the VVO enabled 33F4 feeder increased total annual energy from 33,996 MWh to 34,279 MWh when compared to step 2. Annual energy savings from step 1 have decreased to 4.4%. While total annual energy from step 1 has still been reduced, it can be seen that the addition of DG has a negative impact on the benefits of VVO.

Figure 2

Step 1 - Current State		
Feeder	**Total MWh**	
33F4	35,864	
Step 2- VVO Enabled Feeder		**% Savings from Step 1**
Feeder	**Total MWh**	
33F4	33,996	5.2%
Step 3 - VVO Enabled Feeder with DG		**% Savings from Step 1**
Feeder	**Total MWh**	
33F4	34,279	4.4%

Step 4: Enabling Grid Modernization Functions (i.e., Inverter Volt-Var Controls)

This last analysis step will show how grid modernization functionality can regain the benefits of VVO. Volt-Var controls were enabled on PV inverters to allow inverters to operate at off-unity power factors when needed and control voltage. DG sites were modeled to operate at a leading power factor to absorb reactive power at voltages above 0.97 per-unit (97 % of nominal voltage). By doing so, the voltage rise due to generation is greatly reduced. Total annual energy was again calculated for the entire analysis year and the results are shown below in **Figure 3.** By enabling VVO and utilizing grid modernization functionality mentioned above on the Tiverton 33F4 feeder, total annual energy decreased from 34,279 MWh to 33,981 MWh when compared to step 3. Annual energy savings from step 1 have increased to 5.3%. Note that the addition of DG with grid modernization functionality to a VVO enabled feeder has increased the effectiveness of the original VVO system.

This step also identified the importance of adjustable and dispatchable volt-var curves. Current standard DG volt-var curves, which are focused on alignment with ANSI guidelines, can further reduce VVO system effectiveness by increasing lower range voltages. DG volt-var curves should ultimately be customized to the needs of the specific circuit and be dispatchable through a DER Monitor/Manage system to maximize VVO benefits.

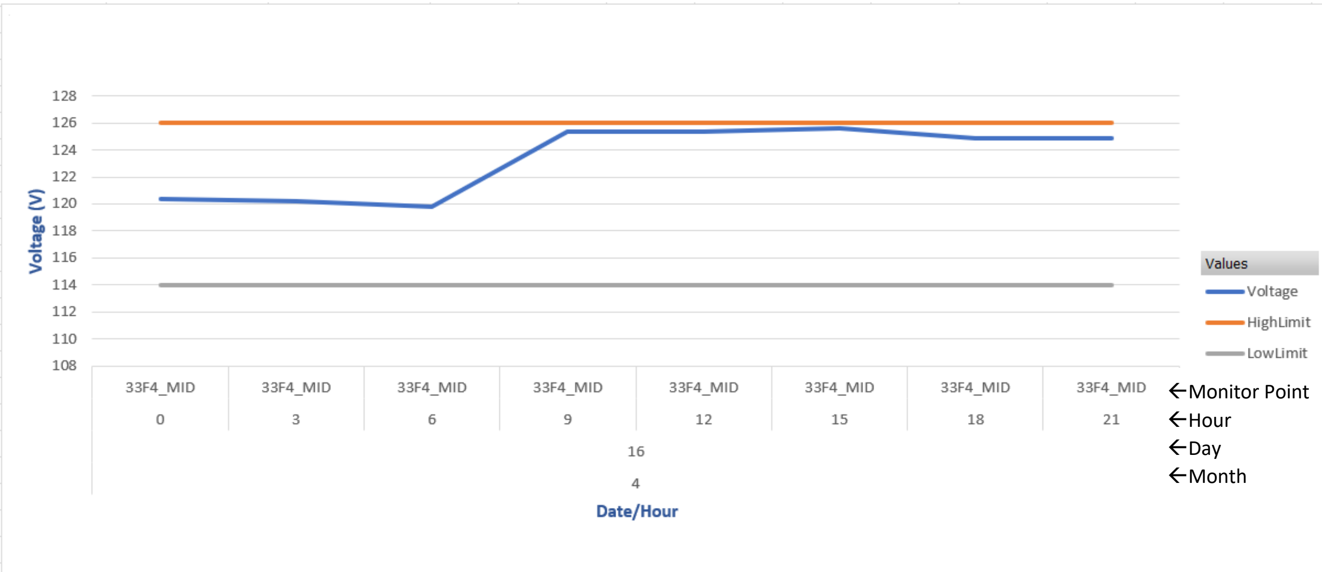
Figure 3

Step 1 - Current State		
Feeder	**Total MWh**	
33F4	35,864	
Step 2- VVO Enabled Feeder		**% Savings from Step 1**
Feeder	**Total MWh**	
33F4	33,996	5.2%
Step 3 - VVO Enabled Feeder with DG		**% Savings from Step 1**
Feeder	**Total MWh**	
33F4	34,279	4.4%
Step 4 - VVO Enabled Feeder with DG and GMP		**% Savings from Step 1**
Feeder	**Total MWh**	
33F4	33,981	5.3%

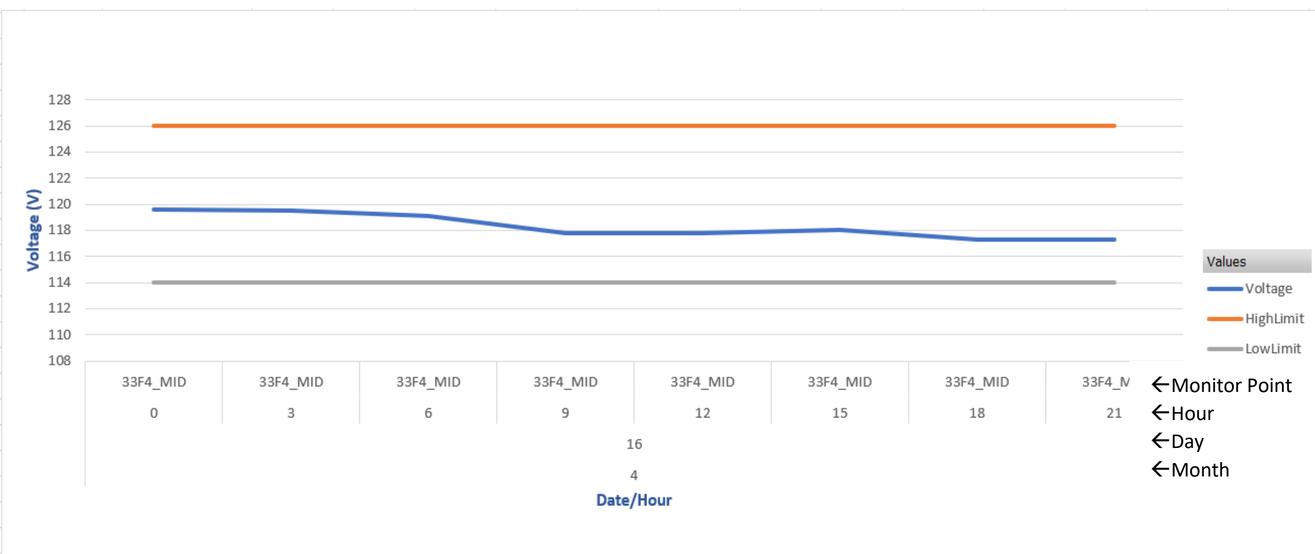
Tiverton 33F4 Voltage Profiles

Throughout the analysis, voltage was monitored in the model on the Tiverton 33F4 feeder for each analysis step. Voltage profiles with a 120 V base at the mid-point of the 33F4 feeder will be shown below for each analysis step on one representative day to show how feeder voltage was impacted during each analysis step. Each profile will also show the high and low ANSI voltage limits (126 V and 114 V respectively).

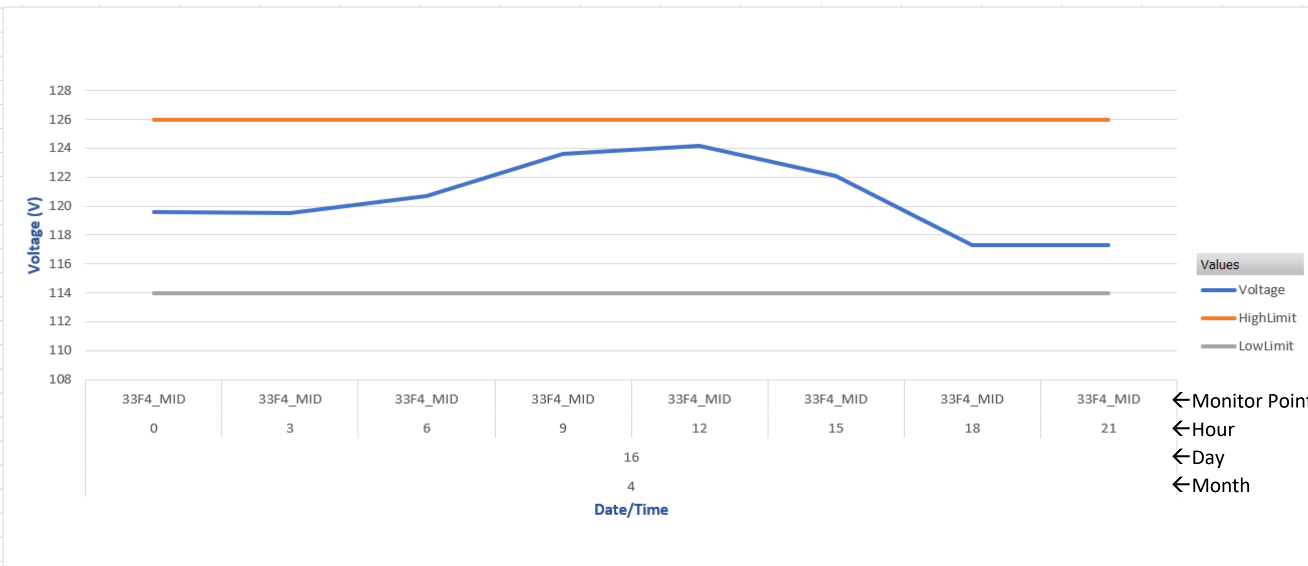
Step 1: Voltage (before VVO)



Step 2: Voltage (VVO enabled feeder)



Step 3: Voltage (VVO enabled feeder with the addition of DG)



Step 4: Voltage (VVO enabled feeder with the addition of DG and GMP)

Conclusions

The analysis above reconfirms that enabling VVO with advanced capacitor and regulator controls greatly reduces voltage on the 33F4 to the lower range of ANSI Range A, increasing energy savings. The analysis above also concludes that the addition of DG increases voltage on the 33F4, decreasing energy savings and lowering the effectiveness of VVO. Furthermore, the analysis shows that the benefits of VVO can be regained by utilizing DG with grid modernization functionality (inverter volt-var control). Lastly, the analysis identified the importance of adjustable and dispatchable DG volt-var curves customizable to specific circuits and specific times of the day to ultimately maximize VVO benefits. With further refinement, grid modernized VVO systems can potentially exceed the benefits of the original technology.

By comparing the tables and voltage plots in Analysis Results, it can be seen how the annual energy savings and feeder voltage are related, as lowering overall voltage to reduce energy is the main principal of VVO. This analysis has also shown the importance of the grid modernization with the proliferation of DG on Rhode Island Energy distribution feeders. By enabling grid modernization functionality, energy savings were maximized, even with a high penetration of DG.

Attachment M

Attachment M:

Example Triggers for NCRI Distribution Study Fixes

This Attachment uses an example to describe the process that was used where triggers cause an action to define a fix such as an infrastructure upgrade to address a particular system violation for the Distribution Study described in Section 5. The geographical circuit maps and tables included in this Attachment illustrate criteria violations that were triggered or identified in the North Central Rhode Island (NCRI) Area by either exceeding allowable voltage thresholds or thermal loading levels in both the No Grid Modernization and the Grid Modernization alternatives where fixes/infrastructure upgrades were applied to obviate the violations.

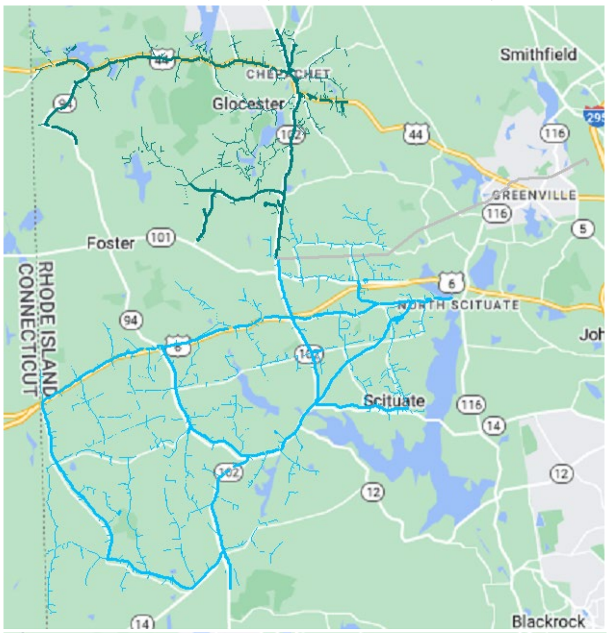
The first example (1.a.) shows the thermal overloads and voltage violations that were identified in the 2050 winter peak case without any fixes. To address the violations fixes were selected for the No Grid Modernization alternative and for the Grid Modernization alternative.

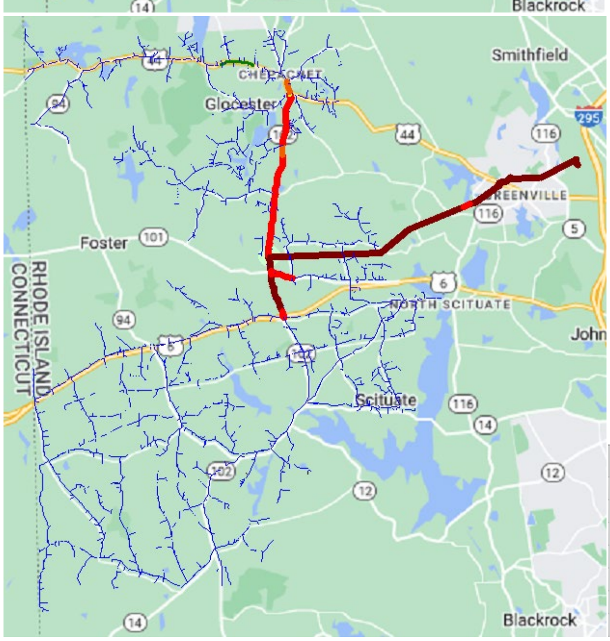
- For the No Grid Modernization alternative, Figure 1.b shows how new feeders were required to eliminate the criteria violations.
- For the Grid Modernization alternative, Figure 1.c shows how battery energy storage system (BESS) is used in conjunction with DER Monitor/Manage functionality provided in the Foundational Investments to mitigate the violations without the addition of new feeders. In addition to solving this system violation, the BESS operated with DER Monitor/Manage will also add many other system benefits such as reducing annual DER curtailment as quantified in the BCA in Section 8.

The maps and tables in this Attachment illustrate the criteria violations and the fixes that were selected for the No Grid Modernization and Grid Modernization alternatives for the spring/light load period of 2050 and the same periods for 2040. Care was taken the ensure that infrastructure investments made in the earlier years provided long-term system benefits and were not obviated by future infrastructure investments. Each of the 11 Planning Areas in Rhode Island were analyzed in this manner.

Overload during Forward Peak Load

1. 34F1 and 34F2 Overloads at 2/13/50 6PM
   a. Overloads without Any fixes (Newton-Raphson)





Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	80.0	1	
80.0	90.0	2	
90.0	95.0	3	
95.0	100.0	4	
100.0	105.0	4	
105.0	150.0	5	
150.0	999999.0	5	

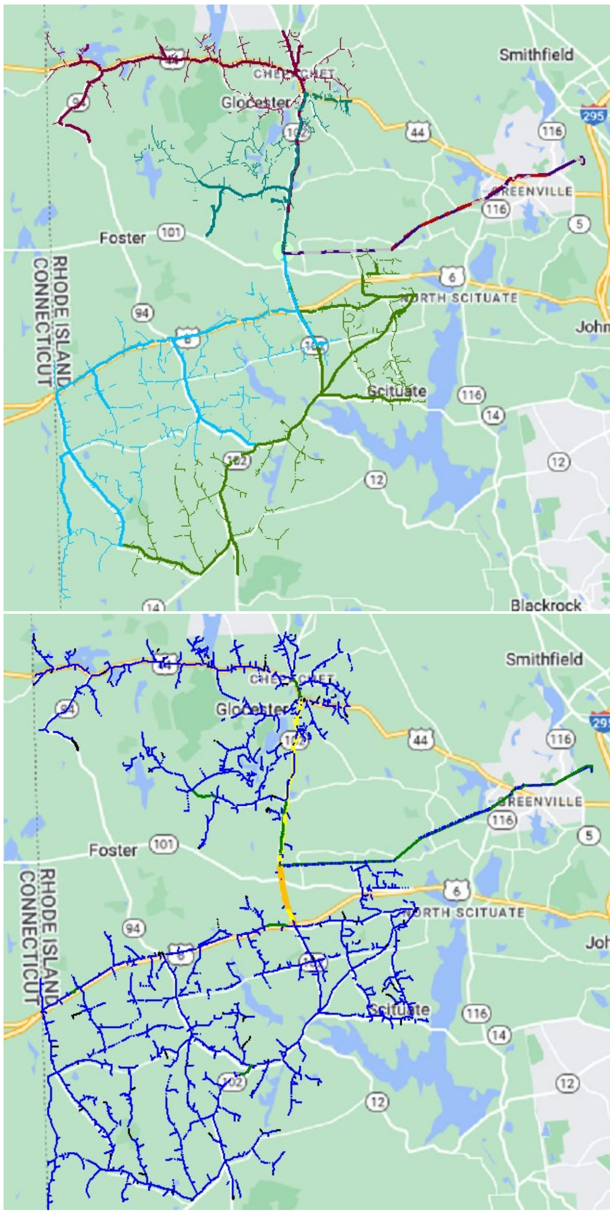
34F1 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	98.9	5.9	784.5	121.6	4654.0	4626.3	507.4	99.40	3490.20
B	96.6	5.8	866.8	134.4	5022.2	5012.0	320.1	99.80	3785.93
C	96.1	5.8	886.2	137.4	5112.5	5078.9	585.1	99.34	3864.66
N			71.7	29.6					
Average:	97.2	7.2	845.8	137.4				99.52	
Total:					14785	14717	1413		11140.79
Unbalance:					274.277				

34F2 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	100.2	6.0	750.5	145.7	4518.7	4505.4	346.5	99.71	3425.10
B	96.0	5.8	755.2	146.6	4355.0	4304.8	659.4	98.85	3289.14
C	98.3	5.9	664.3	129.0	3920.7	3878.4	574.8	98.92	2959.15
N			36.8	15.2					
Average:	98.2	7.2	722.9	146.6				99.17	
Total:					12787	12689	1581		9673.39
Unbalance:					341.495				

b. 34F4 and 34F5 feeders introduced as No Grid Modernization alternative fixes to eliminate overloads:



Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	80.0	1	
80.0	90.0	2	
90.0	95.0	3	
95.0	100.0	4	
100.0	105.0	4	
105.0	150.0	5	
150.0	999999.0	5	

34F1 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	124.8	7.5	512.7	79.5	3839.6	3824.1	-345.0	-99.60	232.87
B	124.7	7.5	521.4	80.8	3900.5	3886.1	-335.5	-99.63	269.91
C	124.7	7.5	513.0	79.5	3837.5	3824.0	-322.1	-99.65	282.21
N			6.3	2.6					
Average:	124.7	7.2	515.7	80.8				-99.62	
Total:					11578	11534	-1003		784.98
Unbalance:					41.336				

34F4 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	122.1	7.3	516.3	96.5	3784.5	3783.9	-66.4	-99.98	235.15
B	122.3	7.3	528.6	98.8	3879.5	3879.2	43.8	99.99	227.79
C	122.5	7.4	499.2	93.3	3669.9	3666.8	-150.6	-99.92	133.89
N			34.0						
Average:	122.3	7.2	514.5	98.8				-99.97	
Total:					11331	11330	-173		596.84
Unbalance:					107.208				

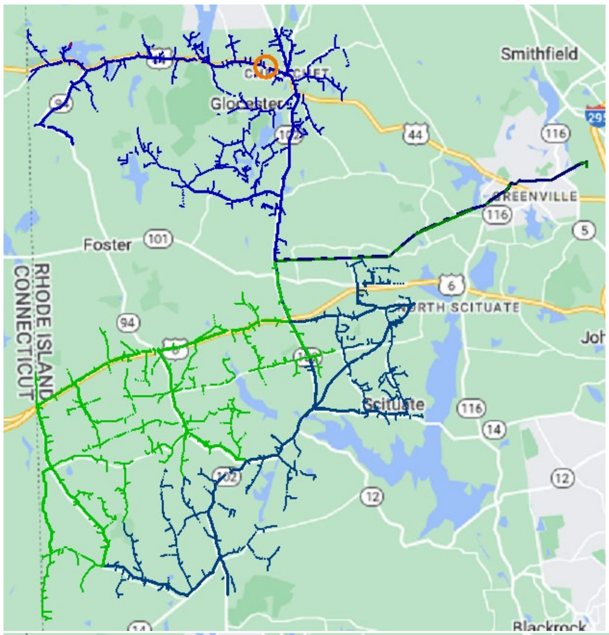
34F2 Getaway Loading:

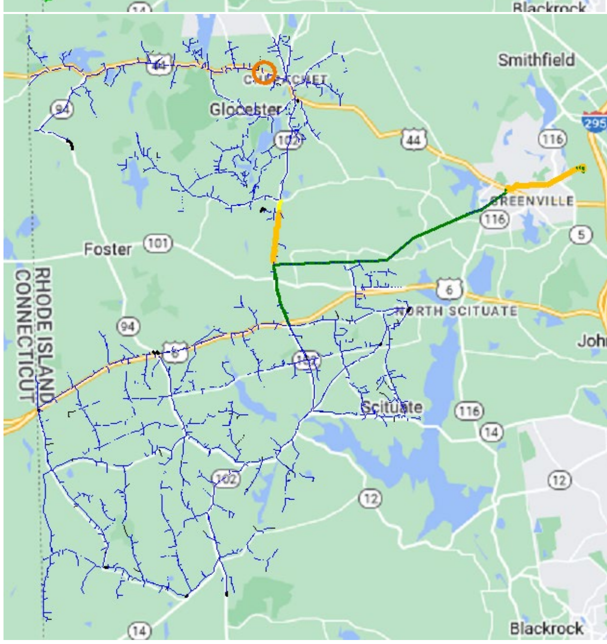
	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	126.1	7.6	478.1	92.8	3618.3	3616.0	127.2	99.94	156.12
B	125.1	7.5	413.4	80.3	3104.6	3104.4	31.9	99.99	108.73
C	125.7	7.5	396.3	77.0	2989.2	2989.1	-15.1	-100.00	124.16
N			82.6	34.1					
Average:	125.6	7.2	429.1	92.8				99.97	
Total:					9711	9710	144		389.01
Unbalance:					381.393				

34F5 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	125.8	7.5	484.8	91.5	3660.4	3655.4	191.9	99.86	300.87
B	125.7	7.5	469.0	88.5	3537.1	3531.8	194.0	99.85	267.97
C	125.8	7.5	448.5	84.6	3385.3	3384.2	89.2	99.97	234.05
N			38.3	15.8					
Average:	125.8	7.2	467.3	91.5				99.89	
Total:					10582	10571	475		802.89
Unbalance:					142.009				

c. 5MW battery (circled in orange) on 34F2 and 34F5 feeders introduced as Grid Modernization alternative fixes to eliminate overloads:





Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	80.0	1	
80.0	90.0	2	
90.0	95.0	3	
95.0	100.0	4	
100.0	105.0	4	
105.0	150.0	5	
150.0	999999.0	5	

34F1 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	124.4	7.5	469.3	72.8	3501.9	3470.0	-472.2	-99.09	207.51
B	124.5	7.5	469.1	72.7	3503.8	3472.9	-464.6	-99.12	216.11
C	124.5	7.5	461.5	71.6	3447.6	3410.8	-502.1	-98.93	221.90
N			11.2	4.6					
Average:	124.5	7.2	466.6	72.8				-99.05	
Total:					10453	10354	-1439		645.52
Unbalance:					36.827				

34F4 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	122.9	7.4	455.7	85.2	3361.0	3355.8	-187.4	-99.84	177.50
B	123.4	7.4	467.4	87.4	3461.4	3459.8	-104.7	-99.95	181.73
C	123.1	7.4	450.0	84.1	3324.1	3315.9	-232.4	-99.76	114.55
N			25.6						
Average:	123.1	7.2	457.6	87.4				-99.85	
Total:					10145	10132	-524		473.78
Unbalance:					79.717				

34F2 Getaway Loading:

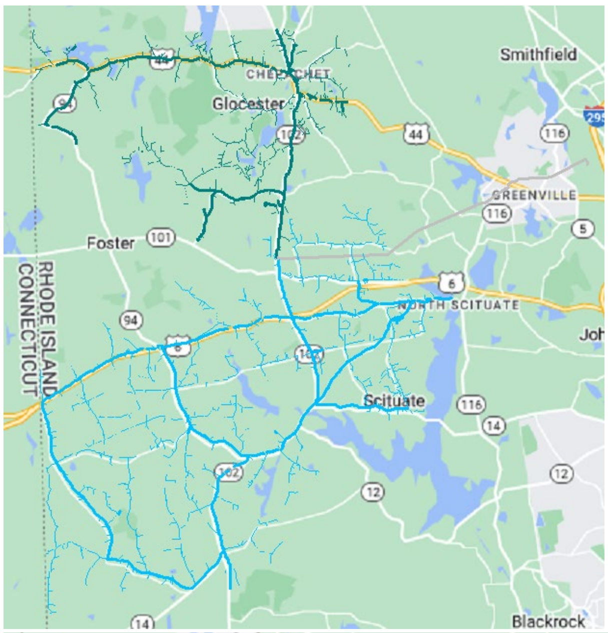
	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	124.8	7.5	513.0	99.6	3843.6	3791.5	631.1	98.64	193.58
B	125.5	7.5	484.0	94.0	3645.9	3611.8	497.1	99.07	211.85
C	125.1	7.5	509.8	99.0	3828.9	3777.7	624.4	98.66	242.95
N			35.3	14.6					
Average:	125.1	7.2	502.2	99.6				98.79	
Total:					11317	11181	1753		648.38
Unbalance:					126.622				

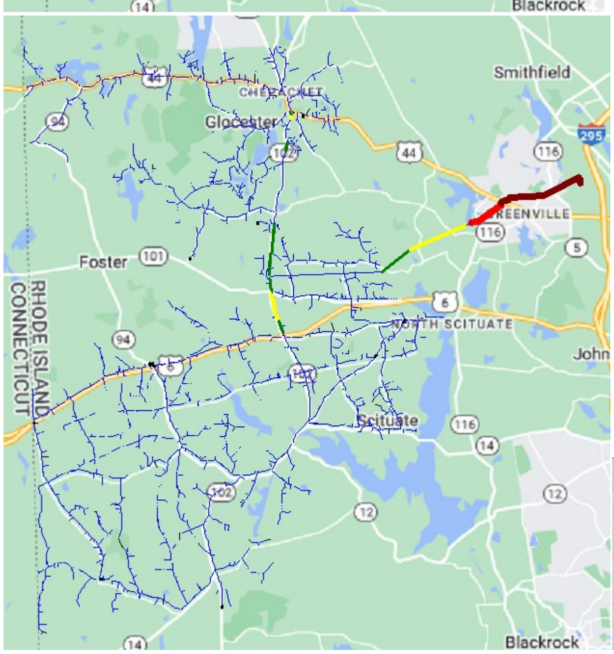
34F2 5MW Battery Discharge Power:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	123.1	7.4	227.8	100.0	1682.6	1682.6	-13.5	-100.00	26.04
B	121.6	7.3	227.8	100.0	1662.1	1661.8	32.8	99.98	43.96
C	121.1	7.3	227.8	100.0	1655.7	1655.6	-19.3	-99.99	33.05
N			0.0						
Average:	121.9	7.2	227.8	100.0				-99.99	
Total:					5000	5000	-0		103.06
Unbalance:					15.966				

Overload during Reverse Peak Load

1. 2221 Overload at 4/16/50 12PM
    a. Overloads without Any fixes:



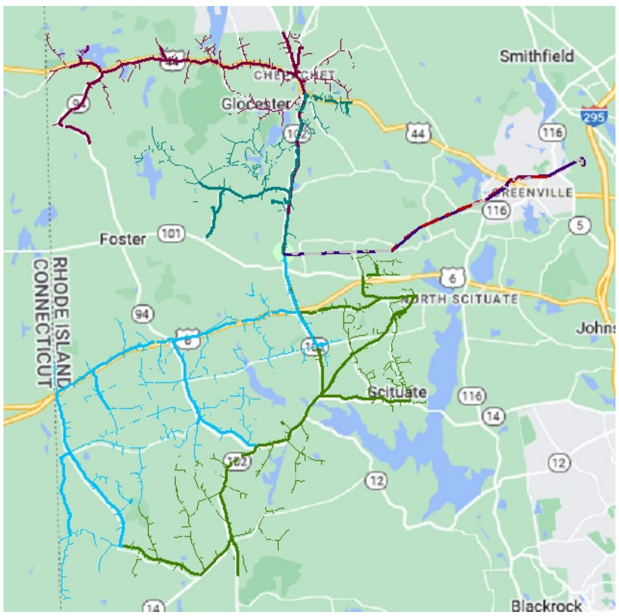


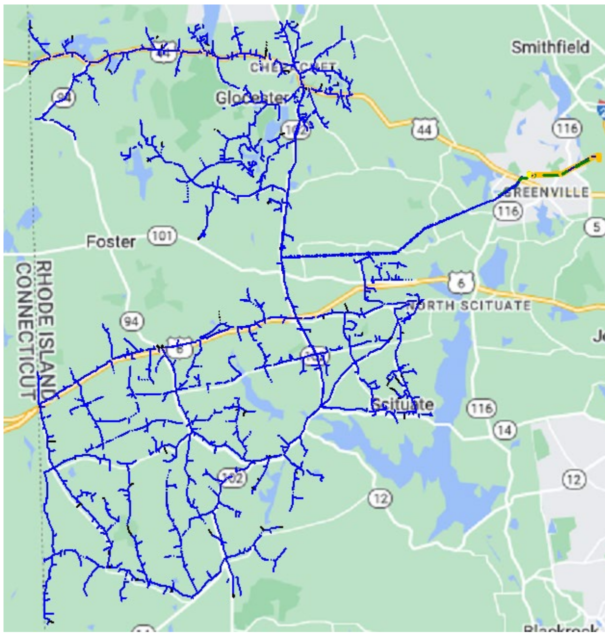
Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	80.0	1	
80.0	90.0	2	
90.0	95.0	3	
95.0	100.0	4	
100.0	105.0	4	
105.0	150.0	5	
150.0	999999.0	5	

2221 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	125.9	13.9	1342.0	260.6	18693.1	-18092.2	4701.8	-96.79	1679.73
B	125.9	13.9	1341.1	260.4	18681.8	-18025.3	4909.0	-96.49	1608.87
C	125.9	13.9	1355.0	263.1	18875.4	-18238.1	4863.4	-96.62	1681.08
N			0.0	0.0					
Average:	125.9	13.3	1346.0	263.1				-96.63	
Total:					56250	-54356	14474		4969.68
Unbalance:					125.529				

b. 2221X and 2221Y sub-transmission introduced as No Grid Modernization alternative fixes to eliminate overloads:





Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	80.0	1	
80.0	90.0	2	
90.0	95.0	3	
95.0	100.0	4	
100.0	105.0	4	
105.0	150.0	5	
150.0	999999.0	5	

2221 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	123.0	13.6	510.6	99.2	6950.2	-6885.4	946.8	-99.07	263.91
B	123.0	13.6	512.6	99.5	6977.2	-6907.4	984.4	-99.00	266.65
C	123.0	13.6	513.8	99.8	6993.3	-6929.0	946.5	-99.08	272.33
N			0.0	0.0					
Average:	123.0	13.3	512.3	99.8				-99.05	
Total:					20921	-20722	2878		802.89
Unbalance:					23.386				

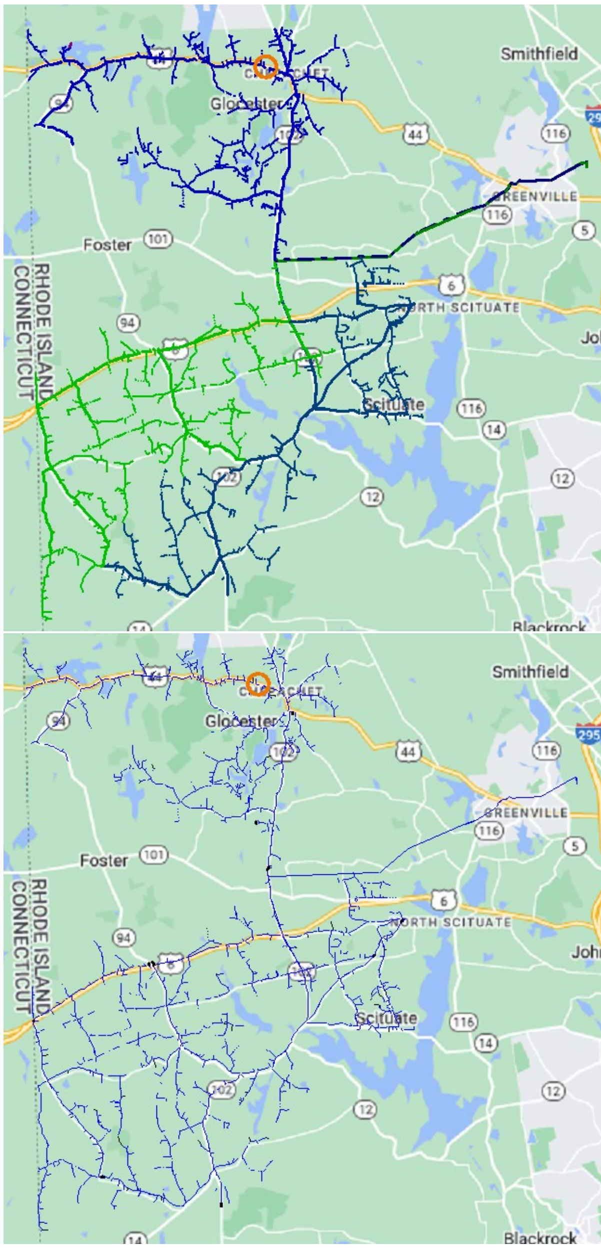
2221X Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	123.0	13.6	469.3	72.8	6387.9	-6281.2	1162.5	-98.33	191.74
B	123.0	13.6	478.1	74.1	6507.1	-6423.2	1042.0	-98.71	228.35
C	123.0	13.6	464.6	72.0	6324.1	-6247.9	979.3	-98.79	191.41
N			0.0	0.0					
Average:	123.0	13.3	470.6	74.1				-98.61	
Total:					19218	-18952	3184		611.50
Unbalance:					101.204				

2221Y Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	120.0	13.3	464.7	86.9	6170.5	-6164.4	273.5	-99.90	96.14
B	120.0	13.3	466.5	87.2	6195.0	-6185.1	350.0	-99.84	90.54
C	120.0	13.3	470.5	87.9	6247.9	-6241.0	293.9	-99.89	110.91
N			0.0						
Average:	120.0	13.3	467.2	87.9				-99.88	
Total:					18613	-18591	917		297.60
Unbalance:					43.533				

c. 5MW battery (circled in orange) on 34F2, which is supplied by 2221, and 2221X feeders introduced as Grid Modernization alternative fixes to eliminate overloads:



Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	80.0	1	
80.0	90.0	2	
90.0	95.0	3	
95.0	100.0	4	
100.0	105.0	4	
105.0	150.0	5	
150.0	999999.0	5	

2221 Getaway Loading:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	123.0	13.6	271.1	52.6	3689.7	-3686.0	-164.6	99.90	100.89
B	123.0	13.6	263.8	51.2	3591.0	-3579.8	-284.1	99.69	94.88
C	123.0	13.6	259.5	50.4	3531.8	-3529.4	-132.4	99.93	106.98
N			0.0	0.0					
Average:	123.0	13.3	264.8	52.6				99.84	
Total:					10811	-10795	-581		302.75
Unbalance:					86.072				

2221X Getaway Loading:

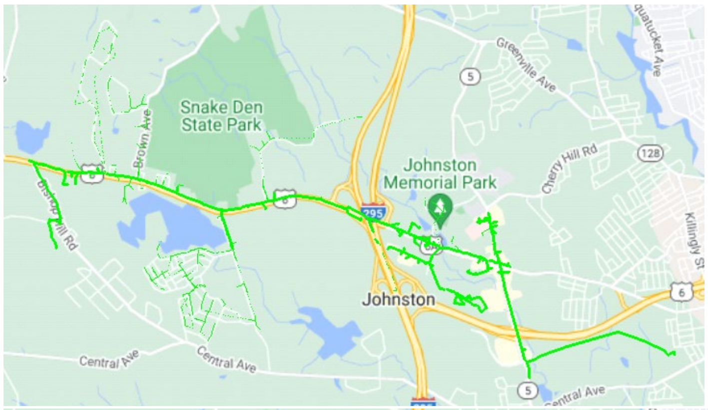
	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	123.0	13.6	464.0	71.9	6315.9	-6264.9	800.7	-99.19	104.99
B	123.0	13.6	468.6	72.6	6377.7	-6313.4	903.1	-98.99	107.57
C	123.0	13.6	472.3	73.2	6429.1	-6377.9	809.9	-99.20	118.34
N			0.0	0.0					
Average:	123.0	13.3	468.3	73.2				-99.13	
Total:					19122	-18956	2514		330.90
Unbalance:					58.149				

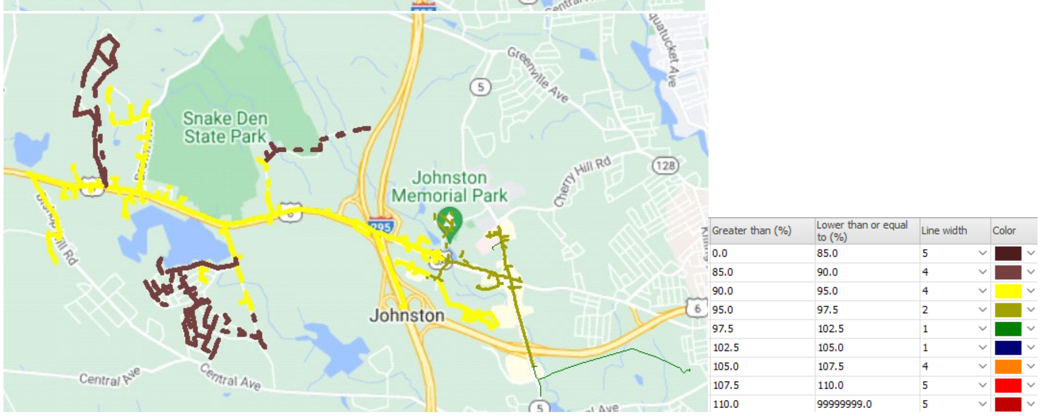
34F2 5MW Battery Charge Power:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	123.3	7.4	225.9	100.0	1671.3	-1671.2	14.0	-100.00	4.66
B	123.2	7.4	225.9	100.0	1670.4	-1670.2	-19.4	99.99	2.87
C	122.4	7.3	225.9	100.0	1658.6	-1658.6	5.4	-100.00	4.66
N			0.0						
Average:	123.0	7.2	225.9	100.0				-100.00	
Total:					5000	-5000	0		12.19
Unbalance:					8.066				

Undervoltage at Forward Peak Load

1. 18F6 Undervoltage at 2/24/40 6AM
   a. Undervoltages without Any Fixes:

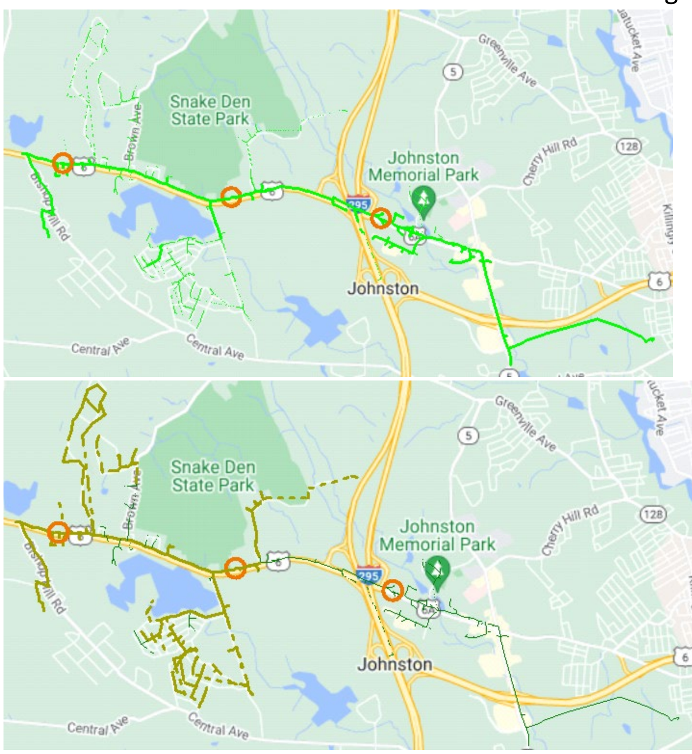




18F6 Remote End Undervoltage:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	108.7	6.5	9.3	3.6	60.3	-14.3	-58.6	23.74	0.17
B	109.2	6.6	9.3	3.6	60.6	-44.0	41.7	-72.53	0.17
C	111.5	6.7	9.3	3.6	61.9	58.8	19.4	94.95	0.17
N			27.8	11.5					
Average:	109.8	7.2	0.0	3.6				0.27	
Total:					3	0	3		0.50
Unbalance:					61.024				

b. Rephasing, one new voltage-controlled capacitor (circled in orange), two existing capacitors made voltage-controlled (circled in orange), adding phases and reconductoring introduced as Grid Modernization alternative and No Grid Modernization alternative fixes to eliminate undervoltage:



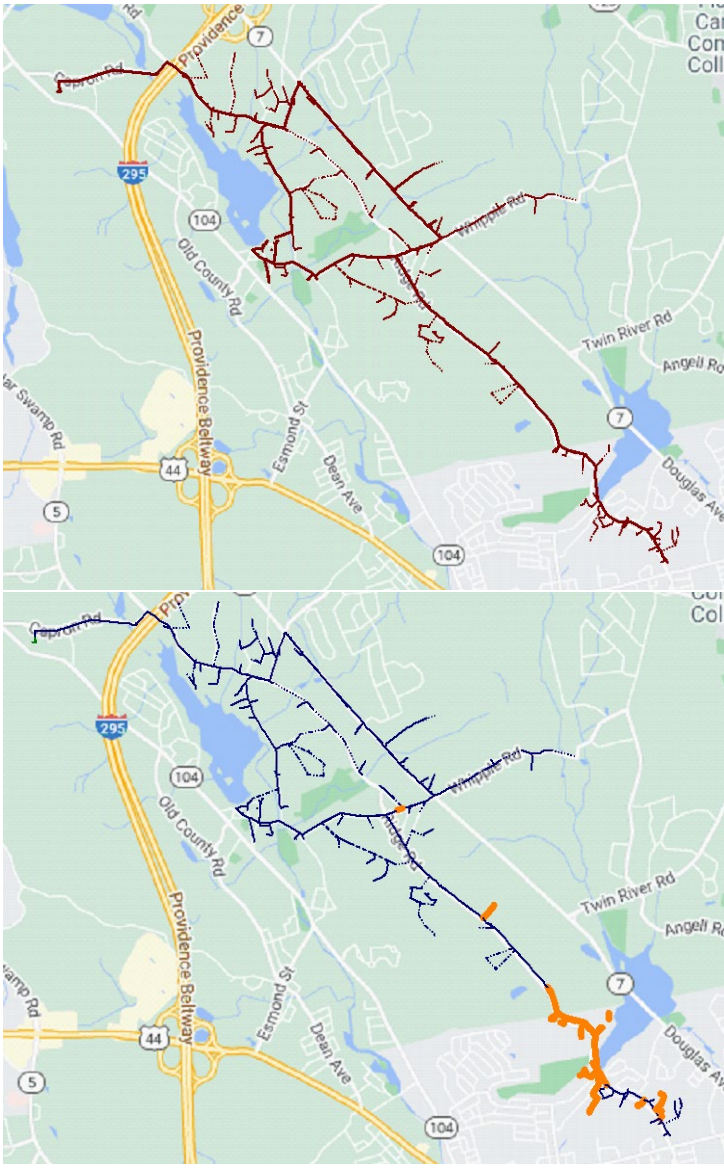
Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	85.0	5	
85.0	90.0	4	
90.0	95.0	4	
95.0	97.5	2	
97.5	102.5	1	
102.5	105.0	1	
105.0	107.5	4	
107.5	110.0	5	
110.0	99999999.0	5	

18F6 Remote End Undervoltage:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	117.0	7.0	2.3	0.9	15.9	5.6	-14.9	-35.24	0.02
B	116.8	7.0	2.3	0.9	15.8	-15.6	2.7	-98.57	0.02
C	117.9	7.1	2.3	0.9	16.0	10.1	12.4	62.95	0.02
N			6.8	2.8					
Average:	117.2	7.2	0.0	0.9				0.10	
Total:					0	0	0		0.05
Unbalance:					15.909				

Overvoltage at Reverse Peak Load

1. 23F2 at 4/16/40 12PM
    a. Overvoltage without Overvoltage Fixes:

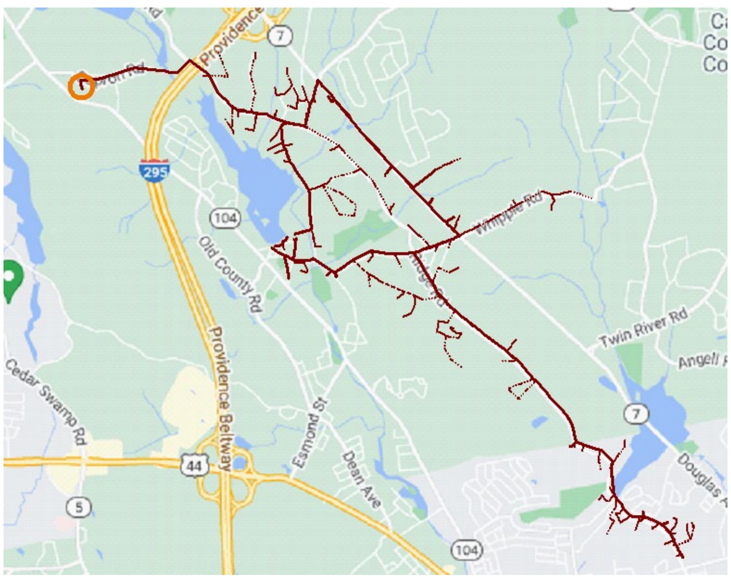


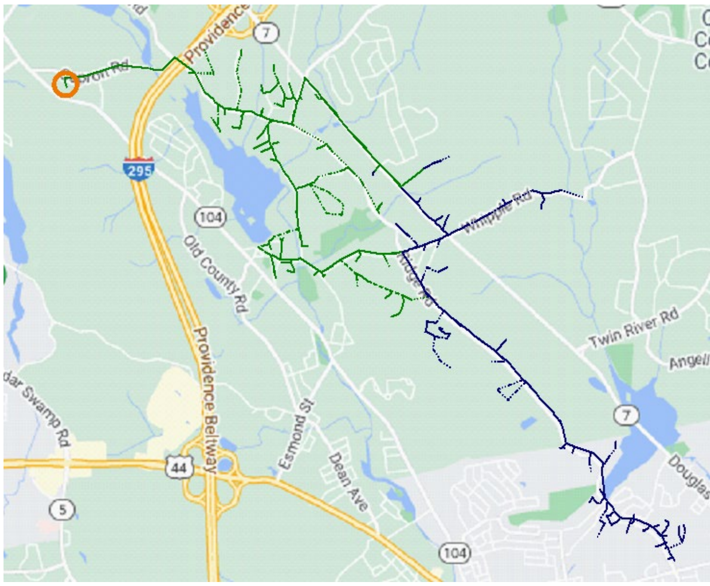
Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	85.0	5	
85.0	90.0	4	
90.0	95.0	4	
95.0	97.5	2	
97.5	102.5	1	
102.5	105.0	1	
105.0	107.5	4	
107.5	110.0	5	
110.0	99999999.0	5	

23F2 Remote End Overvoltage:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	126.7	7.6	37.2	7.0	282.4	-279.5	40.1	-98.98	0.56
B	126.5	7.6	17.0	3.2	128.9	-99.5	81.9	-77.22	0.10
C	126.0	7.6	12.1	2.3	91.1	-12.3	90.3	-13.51	-0.06
N			32.7	13.5					
Average:	126.4	7.2	19.5	7.0				-77.90	
Total:					445	-391	212		0.59
Unbalance:					133.983				

b. Go-generation regulator (circled in orange) introduced as Grid Modernization alternative and No Grid Modernization alternative fixes to eliminate overvoltage:





Greater than (%)	Lower than or equal to (%)	Line width	Color
0.0	85.0	5	
85.0	90.0	4	
90.0	95.0	4	
95.0	97.5	2	
97.5	102.5	1	
102.5	105.0	1	
105.0	107.5	4	
107.5	110.0	5	
110.0	99999999.0	5	

23F2 Remote End Overvoltage:

	V base	kVLN	I (A)	I (%)	kVA	kW	kVAR	PF	Dw kW Loss
A	124.5	7.5	41.6	7.8	310.5	-308.8	32.9	-99.44	0.45
B	124.2	7.5	18.5	3.5	137.8	-113.3	78.5	-82.21	0.11
C	123.8	7.4	12.2	2.3	90.9	-21.3	88.3	-23.43	-0.04
N			35.8	14.8					
Average:	124.2	7.2	21.7	7.8				-82.23	
Total:					486	-443	200		0.52
Unbalance:					148.424				

Attachment N

Attachment N:
Acronym List

Acronym	Description	Acronym	Description
3V0	Zero Sequence Over Voltage Protection	LMI	Low and Moderate Income
ADA	Advanced Data Analytics	LMP	Locational Marginal Price
ADMS	Advanced Distribution Management System	LPG	Liquefied Petroleum Gas
AESC	Avoided Energy Supply Cost	LTC	Load Tap Changing/Changer
AMF	Advanced Metering Functionality	LTE	Long-Term Evolution
AMI	Advanced Metering Infrastructure	LVA	Locational Value Analysis
AMR	Automated Meter Reading	M&V	Measurement and Verification
ANSI	American National Standards Institute	MA	Massachusetts
API	Application Programming Interfaces	Mesh IP	Internet Mesh Telecommunications Network
ARI	Active Resource Initiative	MPLS	Multi-Protocol Label Switching
ASA	Amended Settlement Agreement;	MRP	Multi-Year Rate Plan
AVR	Automatic Voltage Regulation	MV/LV	Medium Voltage/Low Voltage
B/C	Benefit to Cost Ratio	MW	Megawatt
BCA	Benefit Cost Analysis	MWh	Megawatt hour
BCR	Benefit Cost Ratio	NaaS	Network as a Service
BE	Benefit Electrification	NCCETC	North Carolina Clean Energy Technology Center
BTM	Behind The Meter	NEC	National Electric Code

C&I	Commercial and Industrial	NEM	Net Energy Metering
CAPEX	Capital Expenditure	NEP	New England Power
ccEHP	Cold Climate Electric Heat Pump	NERC	North American Reliability Corporation
CEATI	Centre for Energy Advancement through Technological Inovation	NG	National Grid
CEMP	Customer Energy Management Platform	NIC	Network Interface Card
CEP	Customer Engagement Plan	NIEHS	National Institute of Environmental Health Services
CIS	Customer Information System	NIST	National Institute of Standards and Technology
CO2	Carbon Dioxide	NIST SP	National Institute of Standards and Technology Special Publication
COR	Cost of Removal	NITS	Network Integration Service Rate
CP	Customer Portal	NOC	Network Operations Center
CPP	Critical Peak Pricing	NOx	Nitrogen Oxide
CPR	Critical Peak Rebate	NPP	Non-Regulated Power Producer
CSS	Customer Service System	NPV	Net Present Value
CVR	Conservation Voltage Reduction	NWA	Non-Wires Alternative
DA	Distribution Automation	O&M	Operating and Maintenance
DER	Distributed Energy Resources	OER	Office of Energy Resources
DERMS	Distributed Energy Resource Management System	OMS	Outage Management System
DG	Distributed Generation	OPEX	Operating Expense
DLM	Dynamic Load Management	OTA	Over The Air
DMX	Data Multiplexer	P2G	Power-to-Gas
DOE	Department of Energy	PA	Pennsylvania

DOT	Department of Transportation	PI	Program Increment
DP&L	Dayton Power and Light (Ohio)	PI Historian	Plant Information Historian
DPAM	Distribution Planning & Asset Management	PII	Personal Identifiable Information
DR	Demand Response	PIM	Performance Incentive Mechanism
DRIPE	Demand Reduction Induced Price Effect	PLC	Power-Line Communication
DSCADA	Distributed Supervisory Control and Data Acquisition	PMO	Program Management Office
DSIP	Distributed System Implementation Plan	PMP	Point-to-Multipoint
DSP	Distributed System Platform	PPE	Personal Protective Equipment
DSPx	Next-Generation Distribution System Platform	PPL	Pennsylvania Power & Light
D-System	Distribution System	PPL EU	Pennsylvania Power & Light Electric Utilities
EBU	Electric Business Unit	PST	Power Sector Transformation
EC4	Executive Climate Change Coordinating Council	PUC	Public Utilities Commission
EDI	Electronic Data Interchange	PV	Photo Voltaic
EE	Energy Efficiency	REC	Renewable Energy Credit
EEI	Energy Efficiency Initiative	REG	Renewable Energy Growth
EEPP	Energy Efficiency Program Plan	REGP	Renewable Energy Growth Program
EH/EHP	Electric Heat Pumps	REMI	Regional Economic Models, Inc.
EIA	Energy Information Administration	REV	Reforming the Energy Vision
EM&V	Evaluation, Measurement & Valuation	RF	Radio Frequency

EMF	Electromagnetic Frequency	RFP	Request for Proposal
EMS	Energy Management System	RFS	Request for Solution
EPRI	Electric Power Research Institute	RGGI	Regional Greenhouse Gas Initiative
ES	Energy Storage	RI	Rhode Island
ESB	Enterprise Service Bus	RIE	Rhode Island Energy
EV	Electric Vehicle	RIGL	Rhode Island General Law
FAN	Field Area Network	RIPUC	Rhode Island Public Utilities Commission
FAQ	Frequently Asked Questions	RRA	Resilient Rhode Act
FCC	Federal Communications Commission	RTO	Regional Transmission Organization
FERC	Federal Energy Regulatory Commission	RTP	Real-Time Pricing
FLISR	Fault Location Isolation and Service Restoration	RTU	Remote Terminal Unit
FTE	Full-Time Employee	RY	Rate Year
FTM	Frond-of-the-Meter	SAIDI	System Average Interruption Duration Index
FY	Fiscal Year	SAIFI	System Average Interruption Frequency Index
GB	Green Button	SCADA	Supervisory Control and Data Acquisition
GBC	Green Button Connect/Green Button Connect My Data	SCT	Societal Cost Test
GBD	Green Button Download My Data	SECC	Smart Energy Consumer Collaborative
GDP	Gross Domestic Product	SEPA	Smart Electric Power Alliance
GHG	Greenhouse Gas	SI	System Integration

GIS	Geographic Information System	SLA	Service Level Agreement
GMP	Grid Modernization Plan	SME	Subject Matter Expert
GPS	Global Positioning System	SO_2	Sulphur Dioxide
GWH	Gigawatt-hour	SP	Supplier Portal
HAN	Home Area Network	SRP	System Reliability
HCA	Hosting Capacity Analysis	SWSN	Statewide Shared Network
HER	Home Energy Report	T&D	Transmission and Distribution
ICAP	Installed Capacity	T-D	Transmission-Distribution (Interface)
ICE	Interruption Cost Estimate	TMS	Transmission Management System
IEEE	Institute of Electrical and Electronic Engineers	TOU	Time of Use
IEI	Edison Foundation Institute for Electric Innovation	TRC	Total Resource Cost
IHD	In-Home Device	TSA	Transition Service Agreement
IoT	Internet of Things	TVR	Time-Varying Rate
IOU	Investor-Owned Utility	UAT	User Acceptance Testing
IP	Internet Protocol	UL	Underwriters Laboratories
ISO NE	Independent System Operator New England	UTC	Unable to Complete
ISR	Infrastructure, Safety, and Reliability	V2G	Vehicle to Grid
IT	Information Technology	Var	Volt/Volt-Ampere Reactive
ITR	Innovation and Technology Readiness	VEE	Validation, Estimation, & Editing
kV	Kilovolt	VMT	Vehicle Miles Traveled
KW	Kilowatt	VPP	Variable Peak Pricing
KWH	Kilowatt-hour	VVO	Volt-Var Optimization
LDV	Light Duty Vehicle	WACC	Weighted Average Cost of Capital

LED	Light-Emitting Diode	WAN	Wide-Area Network