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

Grid Modernization Plan

Vision and Strategy
Direct Testimony of:
David J. Bonenberger

Grid Modernization Plan
Joint Direct Testimony of:
Kathy Castro
Ryan Constable
Wanda Reder

Book 1 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

Filing Letter
& Motion

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Rhode Island Energy™
a PPL company

December 30, 2022

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket No. 22-56-EL- The Narragansett Electric Company d/b/a Rhode Island Energy <u>Grid Modernization Plan</u>

Dear Ms. Massaro:

Enclosed for filing with the Public Utilities Commission ("PUC") is an original and seventeen (17) copies of the Company's[1] Grid Modernization Plan ("GMP") pursuant to Article II, Section C.15.b of the Amended Settlement Agreement ("ASA") approved by the PUC at its Open Meeting on August 24, 2018, in Docket Nos. 4770 and 4780.[2]

<u>Overview</u>

Rhode Island Energy's GMP consists of a holistic suite of grid modernization investments that will provide the Company with the tools and capability for greater operational visibility to manage the electric distribution system more granularly considering a range of distributed energy resources ("DER") adoption levels, accelerated by Rhode Island's ambitious climate mandates, while at the same time maintaining a safe and reliable electric distribution system. The GMP is an informational guidance document that supports the Foundational Investments[3] proposed in the Company's Fiscal Year ("FY") 2024 Electric Infrastructure, Safety, and Reliability ("ISR") Plan (the "FY 2024 Electric ISR Plan") filed in Docket No. 22-53-EL and will support additional grid modernization investments to be proposed in future electric ISR plans. Consequently, the Company is not requesting approval from the PUC for any specific investments or seeking any cost recovery as part of this GMP. Rather, Rhode Island Energy respectfully requests that the PUC issue 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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[1] The Narragansett Electric Company d/b/a Rhode Island Energy (referred to herein as "Rhode Island Energy" or the "Company").

[2] *See* Report and Order No. 23823, Docket Nos. 4770 and 4780 (May 5, 2020). This GMP replaces the filing that the Company previously submitted on January 21, 2021, in Docket No. 5114, while still under National Grid USA ownership. Rhode Island Energy filed a Notice of Withdrawal of that filing in Docket No. 5114 on September 12, 2022.

[3] The Foundational Investments refer to "near term investments," as described in the GMP, which 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. The Foundational Investments 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.

The GMP reflects PPL Corporation's experience implementing grid modernization investments and solutions for PPL Electric Utilities Corporation 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.

Grid modernization does not refer to a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. To that end, the Company's GMP presents a coordinated and integrated plan to serve three purposes:

(1) Foundational Investments. The GMP presents a comprehensive roadmap of the Foundational Investments that are urgently needed in the near-term (i.e., the next six years) to continue to provide safe and reliable service today, and in the future, as the electric distribution grid transforms with the proliferation of DER. These Foundational Investments are also critical to meeting the State's ambitious climate mandates, including the 2021 Act on Climate, that require greater visibility into, and operational capability of, the electric distribution system to maintain safety and reliability.

(2) Future-Term Investments. The GMP describes the future vision for grid modernization with a roadmap of future grid modernization proposals (through 2042) that 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.

(3) Compliance with the ASA. The Company submits that the GMP complies with its obligation under the ASA approved by the PUC in Docket Nos. 4770 and 4780 to file a GMP containing numerous specific components. In particular, Attachment A to this GMP includes "transparent, updated benefit cost analyses that fully incorporate the Docket 4600 framework" [4] as described in Section 8 of the GMP. Figure 1.1 of the GMP provides a summary of the ASA requirements and where each is addressed in the GMP.

For the near- and future-term proposals, the Company has provided a comprehensive benefit-cost analysis ("BCA") demonstrating the promise of significant value from the future capabilities provided – for operations, customers, and society. The Company intends that this GMP will continue to serve as a resource in the future when it proposes these investments. For example, the GMP is a critical complement to the Company's recently filed FY 2024 Electric ISR Plan. Because of the urgent need for the Foundational Investments, the Company has

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[4] *See* Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System, Docket No. 4600, Report and Order No. 22851 (July 31, 2017).

included these investments as non-discretionary investments in the FY 2024 Electric ISR Plan. The Company intends that the PUC and other parties in the FY 2024 Electric ISR Plan docket will reference and rely upon the descriptions, explanations, justifications, and, particularly, the BCA contained in the GMP when evaluating the FY 2024 Electric ISR Plan, as well as future electric ISR plans.

Rhode Island Energy has undertaken a thoughtful and thorough approach to developing the GMP. The Company leveraged the prior work performed by the AMF/GMP Subcommittee of the Power Sector Transformation Advisory Group. The Company also arranged additional meetings with the AMF/GMP Subcommittee in July – December of 2022 to obtain their input on the GMP analysis in preparation for this filing. The Company's filing reflects their contributions. A summary of the stakeholder engagement process is provided in Figure 1.2 of the GMP.

In summary, and as detailed throughout the GMP, implementation of this GMP is critical for maintaining and enhancing 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 State's ambitious climate mandates.

Filing Materials

In support of the Company's filing, enclosed are two (2) books containing the Company's GMP proposal and supporting materials as follows:

Book 1

- Pre-filed Direct Testimony of David J. Bonenberger in support of Rhode Island Energy's vision and the role of grid modernization in Rhode Island; and
- Joint Pre-filed Direct Testimony of Kathy Castro, Ryan Constable, and Wanda Reder in support of the Company's GMP.

Book 2

- Schedule KC/RC/WR-1 - GMP;
- Compliance With Rhode Island Docket 4600 (Attachment A);
- Summary of US Grid Modernization Developments (Attachment B);
- GMP Roadmap: Communications Solutions and Assumptions (Attachment C);
- System Issues Negatively Impacting DER Projects (Attachment D);
- GMP Comparison: National Grid vs. Rhode Island Energy (Attachment E);
- Distribution Study Results By Planning Area (Attachment F);
- DER Monitor/Manage Approach and Functionality (Attachment G);
- GMP Deployment Plan (Attachment H);

- GMP Benefit-Cost Analysis (BCA) Spreadsheet (Attachment I) (CONFIDENTIAL);
- Cybersecurity, Data Privacy, and Data Governance Plan (Attachment J);
- Rhode Island Energy Grid Modernization Loss Study (Attachment K);
- Impact of Distribution Generation and Grid Modernization on Volt-Var Optimization Systems (Attachment L);
- Examples Triggers for NCRI Distribution Study Fixes (Attachment M); and
- Acronym List (Attachment N).

This filing also includes a Motion for Protective Treatment in accordance with Rule 1.3(H)(3) of the PUC Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) ("Rule 1.3(H)"), and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of the confidential BCA Spreadsheet in Excel format as Attachment I to the GMP (the "BCA Model"). Due to the size and voluminous nature of the BCA Model, the Company is providing the PUC with the confidential BCA Model via the PUC's secure website and marked as **"Confidential."** Accordingly, the Company has not included redacted copies of this material for the public filing.

Thank you for your time and attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Jennifer Brooks Hutchinson

Enclosures

cc: Docket No. 22-56-EL Service List
John Bell, Division
Leo Wold, Esq.

Certificate of Service

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

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

Dated: December 30, 2022

Adam M. Ramos

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-56-EL Grid Modernization Plan (GMP)
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STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

In re: The Narragansett Electric Company d/b/a Rhode Island Energy's Grid Modernization Plan	)	Docket No. 22-56-EL

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") respectfully requests that the Rhode Island Public Utilities Commission ("PUC") provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Rule 1.3(H)(3) of the PUC Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) ("Rule 1.3(H)"), and R.I. Gen. Laws § 38-2-2(4)(B). The Company also requests that, pending entry of that ruling, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

Contemporaneously with filing this motion, on December 30, 2022, Rhode Island Energy submitted its Grid Modernization Plan ("GMP") in the above-captioned docket. In that filing, the Company submitted its GMP Benefit-Cost Analysis ("BCA") Spreadsheet in Excel format as Attachment I to the GMP (the "BCA Model"). The BCA Model contains confidential and proprietary commercial and financial information that the Company ordinarily would not share with the public. Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the BCA Model.

II. LEGAL STANDARD

Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act ("APRA"), R.I. Gen. Laws § 38-2-1, *et seq.* APRA establishes the balance between "public access to public records" and protection "from disclosure [of] information about particular individuals maintained in the files of public bodies when disclosure would constitute an unwarranted invasion of personal privacy." Gen. Laws § 38-2-1. Per APRA, "all records maintained or kept on file by any public body" are "public records" to which the public has a right of inspection unless a statutory exception applies. *Id.* § 38-2-3. The definition of "public record" under APRA, however, specifically excludes "trade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." *Id.* § 38-2-2(4)(B). The statute provides that such records "shall not be deemed public." *Id.*

The Rhode Island Supreme Court has held that when documents fall within a specific APRA exemption, they "are not considered to be public records," and "the act does not apply to them." *Providence Journal Co. v. Kane*, 577 A.2d 661, 663 (R.I. 1990). Further, the court has held that "financial or commercial information" under APRA includes information "whose disclosure would be likely either (1) to impair the Government's ability to obtain necessary information in the future, or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained." *Providence Journal Co. v. Convention Ctr. Auth.*, 774 A.2d 40, 47 (R.I. 2001) (internal quotation marks omitted). The first prong of the test is satisfied when information is provided voluntarily to the governmental agency, and that information is of a kind that would not customarily be released to the public by the person from whom it was obtained. *Id.* at 47.

III. BASIS FOR CONFIDENTIALITY

The BCA Model constitutes "commercial or financial information" to which the APRA public disclosure requirements do not apply. *See* Gen. Laws § 38-2-2(4)(B); *Kane*, 577 A.2d at 663. It contains confidential and proprietary commercial and financial information relating to the Company's business operations. The Company ordinarily does not make this information available to the public. The Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding. Therefore, this information satisfies the APRA exception found in Gen. Laws § 38-2-2(4)(B).

Accordingly, Rhode Island Energy respectfully requests that the PUC grant protective treatment to the BCA Model and take the following actions to preserve its confidentiality: (1) maintain the BCA Model as confidential indefinitely; (2) not place the BCA Model on the public docket; and (3) disclose the BCA Model only to the PUC, its attorneys, and staff as necessary to review this docket.

IV. CONCLUSION

For the foregoing reasons, Rhode Island Energy respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY

By its attorney,

____

Jennifer Brooks Hutchinson, Esq. (#6176)
The Narragansett Electric Company d/b/a
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-7288

Dated: December 30, 2022

Testimony of Bonenberger

PRE-FILED DIRECT TESTIMONY

OF

DAVID J. BONENBERGER

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I. <u>Introduction and Qualifications</u>

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

A. My name is David J. Bonenberger. My business address is 280 Melrose Street, Providence, Rhode Island 02903.

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

A. I am the President of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), an indirect wholly-owned subsidiary of PPL Corporation ("PPL").

Q. What are your principal responsibilities in that position?

A. As President of Rhode Island Energy, I have responsibility for overseeing the regulated electric and gas distribution operations of PPL in Rhode Island provided by Rhode Island Energy and for providing safe and reliable service to Rhode Island customers, while achieving Rhode Island Energy's operational and financial performance objectives.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in accounting from Bloomsburg University and a Master of Business Administration from Wilkes University.

I originally joined PPL in 1984 as assistant field office manager at PPL's Susquehanna nuclear power plant. Over the course of my tenure, I held various positions in the corporate audit, financial, customer service and operations departments with increased levels of responsibility. I played a key role in the startup of the PPL EnergyPlus retail business and PPL Solutions in the unregulated markets. I served as Vice President of Distribution Operations, from July 2011 until January 2018. During this time, I was responsible for the implementation of PPL Electric Utilities Corporation's ("PPL Electric") smart grid program, which resulted in the biggest reliability improvement in PPL Electric's history. I also served as General Manager of Transmission & Substations, Director of Distribution Operations and Regional Director of the utility's central region. I also served as the Vice President of Transmission & Substations for PPL Electric, overseeing the operations, planning, engineering, project and construction management, siting, real estate, and compliance to ensure safe and reliable service while providing exceptional customer service at a reasonable cost. Before becoming President of Rhode Island Energy, I was Vice President of Operations Integration for PPL and was responsible for overseeing the integration planning and implementation to bring The Narragansett Electric Company into the PPL organization, including the creation of transition/integration strategy, implementation of change management across multiple stakeholder groups, and achievement of acquisition business case revenue and pretax income.

Q. Do you have any other professional experience that assists you in your current role in overseeing the safety and reliability of the electric and gas distribution systems in Rhode Island?

A. Yes. I am a member of several industry organizations, including the Edison Electric Institute's ("EEI") Preparedness & Recovery Executive Advisory Committee, the Electric Power Research Institute's Transmission Executive Advisory Committee, the South-eastern Electric Exchange Executive Engineering and Operations Committee, and the Association of Edison Illuminating Companies' Power Delivery Committee. I also am the Chair Emeritus of the EEI National Response Executive Committee.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC" or the "Commission") or any other regulatory commissions?

A. I have not yet provided oral testimony before the PUC, but I recently submitted Pre-Filed Direct Testimony in support of the Company's Advanced Metering Functionality ("AMF") Business Case filed with the PUC in Docket No. 22-49-EL. Additionally, I testified on behalf of PPL and PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, before the Rhode Island Division of Public Utilities and Carriers (the "Division") in Docket No. D-21-09, in which the Division reviewed and approved PPL Rhode Island Holdings, LLC's acquisition of 100 percent of the outstanding shares of common stock of The Narragansett Electric Company from National Grid USA (the "Acquisition").

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to introduce Rhode Island Energy and to describe its vision and strategy for the future of electric operations in Rhode Island. In particular, this testimony describes the approach Rhode Island Energy has taken to develop the Grid Modernization Plan ("GMP") and how the GMP aligns with that vision and strategy. Additionally, my testimony explains how PPL's experience with making grid modernization investments in its other jurisdictions – particularly Pennsylvania – informs Rhode Island Energy's GMP and will benefit Rhode Island.

Q. How is your testimony organized?

A. My testimony is organized as follows: Section I is the Introduction. Section II discusses Rhode Island Energy's vision for the future of energy and how the GMP aligns with that vision. Section III describes PPL's experience with grid modernization investments and how that experience informs Rhode Island Energy's GMP and will benefit Rhode Island. Section IV highlights certain aspects of the GMP as key examples of how the proposed grid modernization investments will not only ensure the continued delivery of safe and reliable service to customers in Rhode Island, but also will deliver significant benefits to transition to a modern electric distribution system. Section V is the conclusion.

II. Rhode Island Energy's Vision

Q. Please describe Rhode Island Energy and its vision for Rhode Island.

A. Rhode Island Energy is the primary provider of electric and gas distribution services in Rhode Island. Rhode Island Energy's vision is aligned with PPL's mission to provide safe, affordable, reliable, and sustainable energy to its customers. PPL has a rich history of providing safe, reliable, and affordable service for PPL customers, demonstrated by its numerous awards for customer satisfaction and national recognition for its operational performance through AMF implementation and grid modernization investments.[1] PPL also has a superior customer satisfaction record, having been awarded 58 total J.D. Power residential and business customer satisfaction

[1] In 2019, PPL's Pennsylvania utility, PPL Electric Utilities Corporation ("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 consecutive years.

awards for its utilities in Pennsylvania and Kentucky combined. PPL brings this history of accomplishment and wealth of experience to Rhode Island Energy and intends to integrate the operational practices that delivered those results into Rhode Island Energy's operations.

Q. What has Rhode Island Energy observed about the nature of Rhode Island's electric distribution system that drives its strategy for the future of energy in Rhode Island?

A. The electric distribution system has begun changing significantly because of: (i) the increasing adoption of additional renewable generation sources, including distributed energy resources ("DER"); (ii) beneficial electrification; (iii) electric vehicles ("EVs"); (iv) electric heat pumps ("EHPs"); and (v) advanced "smart" technologies that enable customers to actively manage energy use in their homes and places of business, and that transformation is expected to accelerate. This transition has fundamentally changed the nature of electric distribution system operations by the need to integrate into many different third-party solutions combined with two-way power flow that is more dynamic, less predictable, and more complicated to manage to ensure safe and reliable electric distribution service. The Company already faces these challenges. The increase in complexity will hasten exponentially with the continued proliferation of DER and as the energy generation industry and Rhode Island Energy act to meet the State's aggressive policy mandates to transition to renewable energy generation and net zero greenhouse gas emissions.

Q. Are there policy mandates under Rhode Island law that impact the Company's vision for the future of the electric distribution system operations?

A. Yes. The 2021 Act on Climate[2] set forth enforceable, statewide, and economy-wide greenhouse gas emissions mandates that require Rhode Island to reduce greenhouse gas emissions by 45 percent below 1990 levels by 2030 and 80 percent 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 resources by requiring that 100 percent of electricity used in the State be generated by renewable energy resources by 2033.[3] These State policy mandates (collectively referred to as the "Climate Mandates") and the actions that energy generators and transmission and distribution utilities must perform to achieve them will cause Rhode Island Energy's operation of the electric distribution system to become much more dynamic and complex.

Q. What is Rhode Island Energy's strategy to address these challenges?

[2] R.I. Gen. Laws § 42-6.2-1 *et seq.*
[3] R.I. Gen. Laws § 39-26-4.

A. To protect electric distribution system safety and reliability and keep pace with this transformation, Rhode Island Energy must invest in the development of a safer and modernized electric distribution system. Accordingly, Rhode Island Energy has evaluated the options available to adapt to these changed circumstances and developed a plan to: (i) make the necessary Foundational Investments now that will provide the necessary, real-time situational awareness of system conditions together with the necessary control capabilities to mitigate these risks; and (ii) facilitate future investments that further enhance the safety and reliability of the electric distribution system while delivering increased benefits. The Foundational Investments described in the GMP are necessary now to address safety and reliability needs and to ensure that the Company is able manage the evolving electric distribution system efficiently and affordably in the future, while maintaining the flexibility to adapt to the actual pace of the energy transition through the adoption of DER and the shift to EVs, EHPs, and other forms of electrification.

Accordingly, Rhode Island Energy's strategy is to be proactive and make the Foundational Investments that will enable the Company to deliver the safe and reliable – and resilient – electric distribution service that customers expect and deserve through improved automation, outage management, and sectionalization capabilities, among others.

Q. How does the Company's GMP align with Rhode Island Energy's vision?

A. Rhode Island Energy has a legal obligation to provide safe and reliable service to its customers.[4] One of the principal reasons that PPL pursued the Acquisition was its determination that the need for the Company to transition to a modernized grid to assist with meeting the State's Climate Mandates was a hand-in-glove fit for PPL's experience in implementing grid modernization investments in Pennsylvania to deliver more reliable service efficiently and affordably. Just as the Climate Mandates position the State as a leader in the transition to renewable energy resources and decarbonization efforts to combat the harmful impacts of climate change, it is Rhode Island Energy's vision to create the electric distribution system that leads the way in facilitating the achievement of those Climate Mandates, while also reducing the frequency and duration of service interruptions to provide an industry-leading customer experience. Rhode Island Energy's vision also includes ensuring that the investments necessary to achieve these goals are affordable to customers, as PPL has done in Pennsylvania.

[4] R.I. Gen. Laws § 39-2-1(a) ("Every public utility is required to furnish safe, reasonable, and adequate services and facilities.").

The GMP aligns directly with this vision. Rhode Island's planned transition to a decarbonized, clean energy future requires increased capability, visibility, and control for electric distribution system operators. The GMP describes a suite of Foundational Investments to occur over a period of six years that are considered "no regrets," in that these investments are critical and provide benefit no matter the degree and pace of customer adaptation of DER. Rhode Island Energy cannot continue to operate the electric distribution system without the Foundational Investments that provide situational awareness and real-time operations capability to respond quickly to the constantly changing conditions on the increasingly dynamic and complex electric distribution system. These investments facilitate the Company's ability to operate the grid, to minimize effectively and efficiently the number and impact of service interruptions, and to do so with relatively modest bill impacts for the average residential customer. The enablement of capabilities such as Fault Location, Isolation, and Service Restoration ("FLISR") and DER Monitor/Manage will provide benefits that far exceed the cost of the investments.

Then, with the Foundational Investments in place, the Company will be well-positioned to make the future investments outlined in the GMP to further enhance these benefits, while maintaining flexibility to adjust the pace and level of those future investments to account for actual experience in the adoption of DER, EVs, EHPs, and other forms of electrification.[5] The investments in the GMP will put the Company on a trajectory to becoming a top-tier utility in terms of reliability and ensure that the electric distribution system will not be an impediment to the State in meeting its Climate Mandates.

Q. How does the GMP relate to the Company's Electric Infrastructure, Safety, and Reliability ("ISR") plan process?

A. The Company proposes that grid modernization investments described and discussed in the GMP will be proposed for approval through the Company's electric ISR plans. The GMP will be a companion document that the PUC and other stakeholders can refer to and rely upon to understand the nature of the specific proposed investments and how they fit into the Company's overall grid modernization strategy. Additionally, the GMP will be a resource to understand the benefit-cost analysis for the grid modernization investments.

[5] The Company has forecast the level of adoption based on what it expects is necessary to achieve the Climate Mandates. If that level of adoption does not materialize, the Foundational Investments remain necessary and appropriate, but the future investments might be impacted.

Specific to the Company's fiscal year ("FY") 2024 Electric ISR Plan, the GMP is a critical complement. 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. The Company intends that the PUC and other parties in the FY2024 Electric ISR Plan docket (Docket No. 22-53-EL) will reference and rely upon the descriptions, explanations, justifications, and, particularly, the benefit-cost analysis ("BCA") contained in this GMP when evaluating the FY 2024 Electric ISR Plan.

III. <u>PPL's Grid Modernization Experience</u>

Q. Can you describe PPL's experience implementing grid modernization investments?

A. Grid modernization is in different stages of maturity in PPL's Pennsylvania and Kentucky jurisdictions. Although there are differences in timing and prioritization, the same vision of grid modernization is shared across jurisdictions. PPL has been nationally recognized for its successful AMF and GMP deployments as examples of technology innovation and pioneering achievements in the utility industry. For example, the Smart 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" – transforming how DER interact with PPL's electric distribution system.

Q. Has PPL observed customer benefits from grid modernization investments in its other jurisdictions?

A. Yes. PPL Electric customers have benefited from grid modernization investments in Pennsylvania. For example, by applying the technological capabilities from the grid modernization investments with the granular data available from the advanced metering infrastructure deployed in Pennsylvania, the frequency of outages or System Average Interruption Frequency Index ("SAIFI") on the PPL Electric systems has improved over time, as shown in Figure 1.7 of the GMP. This significant accomplishment is a direct result of implementing grid modernization investments, including automation of the electric distribution system with smart recloser installations, microprocessor relays, coupled with the deployment of more than 1.4 million second-generation smart meters.

Additionally, PPL Electric was 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, and it enables more efficient dispatch of restoration crews to pinpointed outage locations, resulting in reduced outage restoration times.

Q. Are there opportunities for synergies with PPL's other utilities with respect to grid modernization investments?

A. Yes. The control center and related back-office investments present the greatest opportunity for synergies, including investments in Advanced Distribution Management System ("ADMS") and future functionality, Information Technology ("IT") infrastructure, and appropriate cyber services. 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.

Q. How has Rhode Island Energy applied its experience in its other jurisdictions in developing the GMP?

A. 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 those experienced by PPL Electric customers.

IV. GMP Investments

Q. Are there any investments in the Company's GMP that you would like to highlight?

A. Although all the investments in the GMP are important and will deliver critical operational improvements and customer benefits, I would like to highlight: (i) FLISR, and (ii) the distributed energy resource management system ("DERMS") coupled with DER Monitor/Manage.

Q. Please summarize FLISR and the benefits it will provide.

A. FLISR will automatically isolate faults and sectionalize loads using advanced reclosers, and automatically restore service to many customers. The investment consists of software with an overlaying control scheme to coordinate multiple load management devices (i.e., Advanced Reclosers & Breakers) on a feeder. It essentially allows the electric distribution system to perform a degree of self-healing in response to outages.

One of the primary benefits of FLISR is that it will reduce the number of customers who experience a sustained outage and will shorten the duration of certain sustained outages.

FLISR also will 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.

Q. Please summarize DERMS and DER Monitor/Manage and the benefits they will provide.

A. The DERMS platform is an extension of ADMS that incorporates DER and offers functionality for power quality management and operational support. The DERMS system dynamically manages DER connected to the electric distribution system to optimize power quality, while encouraging the adoption of distributed generation (like solar). DERMS enables 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 voltage or over-operation of capacitor banks). It provides the ability to dispatch reactive power to improve the power factor of the system, including remote ends of the feeder, which may help reduce distribution system losses. Grid optimization and DER Operational Control through ADMS and DERMS will allow for a higher level of DER operational integration and could be used to reduce interconnection costs and enable larger DER interconnections, making DER more cost effective to deploy in the State.

These DERMS capabilities are unlocked by DER Monitor/Manage. DER Monitor/Manage enables the Company's visibility of DER and ability to manage them through DERMS. To enable DER Monitor/Manage, the Company proposes the use of smart inverters that 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. These smart inverters can also reduce their output power generation at times to avoid escalating system conditions and respond to power curtailment commands.

Q. Why have you chosen to highlight FLISR, DERMS, and DER Monitor/Manage?

A. These investments and their resulting benefits offer a picture of what is necessary to manage the electric distribution system safely and effectively in a manner that will enable the transition to renewable energy generation and decarbonization of the power system to meet the Climate Mandates, while also remaining focused on providing top tier customer service. They provide a picture of Rhode Island Energy's vision of the future.

Q. Please discuss the affordability of the investments proposed in the GMP.

A. First, Rhode Island Energy is not seeking PUC approval of any investments or any specific cost recovery in this docket. Rather, the GMP provides the insight into Rhode

Island Energy's plan for the future. Approval of particular investments and cost recovery for those investments will occur in the annual ISR plan filings.

That said, the GMP presents a very favorable BCA. The forecasted bill impacts for the investments are not severe, particularly compared to the benefits that will flow to customers. Further, making investments in these grid modernization technologies and capabilities now is the prudent, proactive course of action now, rather than waiting to make investments on a reactive basis as the distribution system operations issues they are designed to counteract occur in the future. Further, PPL has a demonstrated record of effectively managing costs to customers while making grid modernization investments and is bringing the operational practices that allowed that to occur to Rhode Island Energy.

V. <u>Conclusion</u>

Q. Do you have any summary comments on Rhode Island Energy's GMP?

A. Yes. Implementation of the grid modernization investments in the 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. The investments are cost effective. The alternative of not moving forward with these investments is likely to create higher costs in the future, while also causing lower-level customer service, safety, and reliability now. 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. Accordingly, the GMP presents a solid roadmap to delivering the energy future Rhode Island and its customers expect and deserve.

Q. Does this conclude your testimony?

A. Yes, it does.

JOINT PRE-FILED DIRECT TESTIMONY

OF

KATHY CASTRO,

RYAN CONSTABLE,

AND

WANDA REDER

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I. <u>Introduction and Qualifications</u>

<u>Kathy Castro</u>

Q. Ms. Castro, please state your name and business address.

A. My name is Kathy Castro. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

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

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or "the Company") as the Director of Asset Management and Engineering. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Please describe your educational background and professional experience.

A. In 2003, I graduated from Worcester Polytechnic Institute with a Bachelor of Science Degree in Electrical Engineering. In the same year, I was employed by National Grid USA Service Company, Inc. ("National Grid Service Company") as an Associate Distribution Design Engineer responsible for design of new facilities for business and capital improvement projects. In 2005, I earned a Graduate level Certificate of Power Systems Management and Engineering from Worcester Polytechnic Institute. In 2005, I joined the Distribution Planning and Engineering department as an Engineer, and I was promoted to Senior Engineer in 2008. In this role, I was responsible for identifying asset, capacity, and reliability issues, justifying proposed solutions, and initiating selected projects for Operations and Substation engineering departments. I also reviewed and recommended solutions to serve customers requiring significant demand. In 2010, I joined a consultant company located in Rockland, Massachusetts, as a Senior Engineer. In this role, I was responsible for completing distribution system impact analysis of distributed generation for utilities across New England and New York. Within one year, I was promoted to Manager of Engineering responsible for building a department that focused on Distribution Planning short- and long-term studies. In 2017, I was promoted to Director of Engineering overseeing Distribution Design and Planning functions. In March of 2018, I returned to National Grid Service Company and assumed the position of Manager of Distribution Planning and Asset Management. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation ("PPL"), acquired 100 percent of the outstanding shares of common stock of the Company from National Grid USA ("National Grid") (the "Acquisition"), at which time, I assumed my current position as Director of Asset Management & Engineering for Rhode Island Energy.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC" or the "Commission") or any other regulatory commissions?

Yes. I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2020 and FY 2021 Electric Infrastructure, Safety, and Reliability ("ISR") Plans.

Ryan Constable

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

A. My name is Ryan M. Constable. My business address is 280 Melrose Street, Providence RI 02907.

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

A. I am employed by Rhode Island Energy as an Engineering Manager in the Distribution Planning and Asset Management Department. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

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

A. I received a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, New York, in 1993 and a Certificate of Industrial Management and Power Engineering from Worcester Polytechnic Institute in Worcester, Massachusetts, in 2000. I am a Registered Professional Engineer in Massachusetts, number 41632. I worked for National Grid Service Company from 1994 to 2000 and from 2010 until the closing of the Acquisition, at which time I assumed my current position with Rhode Island Energy. I have held various positions of increasing responsibility in the area of Distribution Planning. From 1994 to 1998, I was a Project Engineer responsible for the design and maintenance of the electric infrastructure serving commercial and residential customers in southeastern Massachusetts. During the period 1998 to 2000, I was a Planning Engineer conducting long-range electric system studies. From 2010 to 2011, I worked as a Principal Engineer in the Utility of the Future department developing the Worcester Smart Energy Solution Pilot. In 2011, I became the Manager of Distribution Planning and Asset Management – New England, directing a ten-person team to conduct annual planning activities, perform long-range planning studies, and develop regulatory filings. In 2017, I became the Acting Director of the department. In the period 2000 to 2010, I worked for three independent transmission development companies: TransEnergie U.S., Cross Sound Cable Company, and Brookfield Renewable Power.

Q. Have you previously testified before the PUC?

A. Yes. I have previously testified before the PUC in support of the Company's FY2023 Electric ISR Plan in Docket No. 5209, FY2022 Electric ISR Plan in Docket No. 5098, and the Company's FY2020 Electric ISR Reconciliation filing in Docket No. 4915.

<u>Wanda Reder</u>

Q. Ms. Reder, please state your name and business address.

A. My name is Wanda Reder. My business address is 34W676 Country Club Road, Wayne, Illinois 60184.

Q. Ms. Reder, by whom are you employed and in what position?

A. I am the President and CEO of Grid-X Partners, which is a certified Women's Business Enterprise consulting firm that provides insight and direction for electric and gas utility grid transformation. Grid-X Partners brings senior executive experience having a unique balance of technical, strategic and practitioner capability. It assists utilities and their stakeholders in developing strategy, regulatory and execution plans to address the complex challenges confronted by utilities in an evolving industry landscape. As CEO, my primary responsibilities include making all major corporate decisions, financial responsibility, managing the overall operations and resources of the company, and acting as the main point of communication between the consultants and our clients. I am testifying on behalf of Rhode Island Energy.

Q. Ms. Reder, please describe your educational background and professional experience.

A. I earned a Master of Business Administration with emphasis in New Ventures from the University of St. Thomas in St. Paul, Minnesota, and a Bachelor of Science in Engineering from South Dakota State University.

I have more than 30 years of experience in the electric utility industry, with much of my career aimed at grid modernization thought leadership and transformation for electric utilities. Before founding Grid-X Partners, I served as Chief Strategy Officer and Vice President of Power Systems Services for S&C Electric Company ("S&C") from 2004 to

2018. There, I developed consulting, engineering, field services, and project management capability to address global service needs. Among many offerings, we designed, integrated, and commissioned grid-scale distribution automation projects as well as wind-power, solar, and storage projects for utilities and developers. Prior to S&C, I was a Vice President for Exelon Energy Delivery responsible for several areas such as Asset Management, Engineering and Planning. My group of more than 1,000 employees defined the transmission and distribution work portfolio in excess of $1 billion annually, developed and managed the budget, and prepared and scheduled the execution of work. Before Exelon, starting in 1987, I served in various capacities for Northern States Power (now Xcel) in executive and engineering roles, including leading transmission and distribution capacity planning and technology implementation for automated meter reading, distribution automation, distribution management, and demand-side management. I am an Institute of Electrical and Electronics Engineers ("IEEE") Fellow, served as President of the IEEE Power & Energy Society from 2008 to 2009, and was appointed to the U.S. Department of Energy ("DOE") Electricity Advisory Committee by the U.S. Secretary of Energy, serving a six-year term from 2011 to 2017, and again re-appointed in 2018 until the present, where I currently serve as its Chair. Also, I was invited to, and became a member of, the prestigious National Academy of Engineers in 2016 for my leadership in electric power delivery and workforce development, where I currently serve on the Membership Policy and Finance Committees.

Q. Have you previously testified before the PUC?

A. I have not testified before the PUC; however, I recently submitted Joint Pre-Filed Direct Testimony in Docket No. 22-49-EL in connection with the Company's Advanced Metering Functionality ("AMF") Business Case. Prior to that, I presented regarding the AMF Business Case at the Workshop conducted by the PUC in Docket Nos. 4770 and 4780 on September 1, 2022, together with Company Witness Philip J. Walnock, and I presented about the Company's Grid Modernization Plan ("GMP") at the Technical Session on October 18, 2022, related to the Company's FY2023 Electric ISR Plan in Docket No. 5209.

In addition to my work in Rhode Island, I was an expert witness for PPL Electric Utilities Corporation's ("PPL Electric") petition that it filed with the Pennsylvania Public Utility Commission for permission to require smart inverters that meet the 2018 revisions to IEEE Standard 1547, "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" ("IEEE Standard 1547" or "IEEE 1547-2018") and related Underwriters Laboratories ("UL") Standard 1741 to install distributed energy resources ("DER") management devices on new DER interconnected with its distribution system, and to monitor and manage those new DER. My role was to present the background for the IEEE Standard 1547 and showcase global trends and use cases that highlight the importance of the using the IEEE Standard 1547.

II. Purpose, Background, and Structure of Joint Testimony

Q. Please describe the purpose of your joint testimony in this proceeding.

A. The purpose of our joint testimony is to present Rhode Island Energy's Grid Modernization Plan ("GMP") in compliance with Article II, Section C.15 of the Amended Settlement Agreement ("ASA") approved by the PUC in Docket Nos. 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,[1] while at the same time maintaining a safe and reliable electric distribution system. The Company faces an urgent need to address the operational challenges surrounding reliability, safety, and customer satisfaction stemming from existing and future intermittent DER, and to improve service reliability and customer service. To that end, the GMP presents a comprehensive roadmap (the "GMP Roadmap" or "Roadmap") of the Foundational Investments that Rhode Island Energy expects to need in the near term (i.e., next six years) to ensure the continued 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

[1] 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 percent below 1990 levels by 2030, 80 percent 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 resources by requiring 100 percent of electricity used in the State be generated by renewable energy resources by 2033. In this testimony and the GMP, the Company refers to these statutory requirements collectively as the "Climate Mandates."

storage and advanced grid technologies that can incrementally evolve over time commensurate with future DER adoption.

Q. Why are the Foundational Investments necessary?

A. The Foundational Investments, described below and in the GMP, are necessary to provide safe and reliable service today and as the electric distribution grid transforms due to DER proliferation.[2] The Company's existing electric distribution system provides little operator visibility and limited automated control. The Company needs grid modernization enabled by the proposed Foundational Investments now to provide operator visibility and control to enhance safe and reliable system operations and for any future DER adoption scenario.

Q. Why does the Company consider the Foundational Investments so urgent?

A. The GMP cites many examples, trends, and factors supporting the urgent need for the Foundational Investments for Rhode Island Energy, including the following: (i) deteriorating reliability trends; (ii) a lengthening DG interconnection queue; (iii) increased operational risk because of hidden load during switching; (iv) voltage variability; (v) lack of situational awareness; (vi) high DER adoption rates reinforced by the Climate Mandates; and (vii) a compromised supply chain, resulting in imminent delays for material availability.

[2] DER are resources sited close to customers that can provide electricity generation, including both distributed generation ("DG") installations and flexible demand resources (e.g., energy storage, electric vehicles, electric heat pumps).

Q. What does the Company seek from the PUC with this filing?

A. The Company requests that the PUC issue an order that the Company has complied with its obligation to file a GMP that meets the requirements of the ASA approved by the PUC in Docket No. 4770, as described below. The Company does not seek approval of any particular investments or cost recovery as part of this GMP. Rather, the GMP is an informational guidance document providing the Roadmap for near-term and future-term investments.

Q. How does the GMP relate to the Company's FY2024 Electric ISR Plan?

A. Due to the urgent need for the Foundational Investments outlined in the GMP, the Company has included them as non-discretionary investments in the FY2024 Electric ISR Plan, Docket No. 22-53-EL. The Company intends to rely upon the descriptions, explanations, justifications, and, particularly, the benefit-cost analysis ("BCA") for the Foundational Investments contained in the GMP in support of its FY2024 Electric ISR Plan.

Q. How will the GMP relate to future annual Electric ISR Plan review processes?

A. The GMP is intended to serve as a complement to the annual Electric ISR Plan review process, using its comprehensive and long-range plans, GMP Roadmap, deployment plan, and overarching BCA as a reference decisions to guide the Company's future investments. The GMP outlines additional grid modernization investments that the

Company will propose and for which it will seek cost recovery in future electric ISR plans.

Q. Please explain the naming conventions that you will use in your testimony to identify the various entities involved in this proceeding.

A. On May 25, 2022, PPL Rhode Island, LLC, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of The Narragansett Electric Company from National Grid USA and immediately re-branded Narragansett as Rhode Island Energy. This filing is Rhode Island Energy's GMP to modernize Rhode Island Energy's electric distribution grid under PPL's ownership. In this case, we will refer to the regulated entity under PPL's ownership as "Rhode Island Energy" or the "Company." When we refer to PPL Corporation, we will use the term "PPL." When we refer to Narragansett under National Grid USA's ownership, we will use the term "National Grid" to distinguish it from the re-branded entity that is Rhode Island Energy. When referring to "National Grid USA" as the former owner of Narragansett, we will use that precise term.

Q. How is your testimony structured?

A. Sections I and II include an Introduction and Qualifications, and the Purpose, Background, and Structure of the Testimony, respectively. Section III describes how the Company's GMP complies with the requirements of the ASA. Section IV provides an overview of Rhode Island Energy's approach to the GMP. Section V discusses the current state of the electric grid. Section VI describes the functionalities that are needed to transform the grid. Section VII presents the GMPs comprehensive Sub-transmission and Distribution Study (the "Distribution Study") scope and results. Section VIII presents the GMP Roadmap with DER management functionality. Section IX describes risk mitigation, deployment, and accountability. Section X presents the benefit-cost analysis and the Docket 4600 framework. Section XI is the conclusion.

Q. Are you sponsoring any attachments in support of your joint testimony?

A. Yes, we are sponsoring the following attachments:

Schedule KC/RC/WR-1 is the GMP, which includes the following 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 CONFIDENTIAL

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: EXAMPLES TRIGGERS FOR NCRI DISTRIBUTION STUDY FIXES

ATTACHMENT N: ACRONYM LIST

Because the BCA Spreadsheet contains confidential and proprietary commercial and financial information that would ordinarily not be shared with the public, the Company is seeking confidential treatment for Attachment I, pursuant to Rule 1.3(H).

III. Compliance With the ASA

Q. What specifically did the ASA require the Company to do with respect to a grid modernization plan?

A. Article II, Section C.15 of the ASA required the Company to engage with stakeholders to develop and file a comprehensive GMP. 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. The ASA 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.

Q. Did the ASA require the GMP to include specific elements?

A. Yes. The ASA specified twelve requirements that the GMP must include:

a. 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 the Docket 4600 Guidance Document;

b. Explanation of the role of currently active programs;

c. Investments and technology deployments planned through the end of any proposed AMF implementation;

d. Functionalities to achieve those objectives;

e. Review of options for candidate technologies to deliver those functionalities;

f. Transparent, updated benefit cost analyses that fully incorporate the Docket No. 4600 framework;

g. An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments;

h. A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term;

i. Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities;

j. Explanation of congruency with grid modernization activities in New York and Massachusetts;

k. A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; and

l. 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.

Q. Does the GMP 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?

A. Yes. Section 1.7 of the GMP introduces the grid modernization pyramid,[3] which illustrates how grid modernization investments are integrated to provide the necessary visibility and enhanced distribution control for flexible, safe, and reliable modern-day grid operations. Section 3 of the GMP introduces grid modernization functionalities the Company considers necessary to address the present and anticipated future challenges to operations. It includes functionalities identified by the DOE as necessary in its Next-Generation Distribution System Platform Modern Distribution Grid guidelines. Section 3 also defines the benefits that correspond to these functionalities. Section 4 of the GMP identifies the linkage and integration of a wide range of existing and future functionalities, while Section 5 of the GMP considers a No Grid Modernization alternative. The grid modernization solutions identified in the GMP are further outlined in the GMP Roadmap in Section 6 of the GMP and discussed in the Deployment Plan in Attachment H.

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

Q. Does the GMP assess grid modernization technologies over both the short- and long-term and present short- and long-term implementation plans?

A. Yes. Section 6 of the GMP outlines the proposed near-term and long-term solutions. The GMP presents a comprehensive GMP Roadmap of the Foundational Investments necessary in the near-term, defined in the GMP as over the next six years. The GMP also describes investments anticipated through 2042 that will extend the capabilities of the Foundational Investments and can be aligned with the pace of DER adoption.

Q. Does the GMP address the twelve enumerated requirements of the ASA you identified previously?

A. The GMP addresses eleven of the twelve enumerated ASA requirements. Figure 1.1 of the GMP specifies exactly where the GMP addresses each of these requirements.

Q. Which of the twelve ASA requirements does the GMP not address?

A. The GMP does not address the ASA requirement that the GMP explain its congruency with grid modernization activities in New York and Massachusetts. This requirement made sense at the time of the ASA's approval because National Grid USA operated in New York and Massachusetts, in addition to Rhode Island. PPL does not operate in New York and Massachusetts, and congruence with New York and Massachusetts therefore is not applicable to Rhode Island Energy's GMP. That said, this GMP discusses in detail the ways in which PPL Electric's experience and insights from successfully installing grid modernization technologies over the past decade in Pennsylvania can be leveraged for Rhode Island. The Company believes this satisfies the spirit of the ASA's congruency requirement.

Q. In your opinion, does the GMP address all of the requirements for a GMP specified in the ASA?

A. Yes. As we have previewed here, and as is described in detail in the GMP, we believe Rhode Island Energy's GMP addresses all of the requirements set forth in the ASA.

IV. <u>Rhode Island Energy's Approach to the GMP</u>

Q. What is the purpose of the GMP?

A. The GMP has three fundamental purposes:

(1) Demonstrate that the Foundational Investments are necessary and urgently needed to continue to provide safe and reliable service today and as the electric distribution grid transforms due to DER proliferation;

(2) Describe Rhode Island Energy's vision for grid modernization through the GMP Roadmap and comprehensive BCA demonstrating significant value from grid modernization investments; and

(3) Satisfy the Company's obligation under the ASA approved by the PUC in Docket No. 4770 to file a GMP containing the specific components identified above.

The GMP presents a no-regrets investment approach that will provide the Company with the tools and capability for greater operational visibility needed to maintain safety and reliability and is also financially viable considering any range of future DER adoption levels.

Q. What do you mean by a "no regrets" investment?

A. The term "no regrets" is used in planning to indicate that a decision or an investment will be used and useful in virtually any future scenario. In the context of the GMP, the Company uses the term "no regrets" to reflect that the Foundational Investments create a net benefit (or have a positive BCA) under any future scenario evaluated.

Q. How did the Company engage with stakeholders to develop the GMP?

A. The Company, in partnership with the Rhode Island Division of Public Utilities and Carriers and the Rhode Island Office of Energy Resources, established the PST Advisory Group in October 2018 and formed the GMP and AMF Subcommittee to gather stakeholder input for the development of the GMP and the Updated AMF Business Case. Subcommittee members include representatives with a variety of interests, as prescribed by the ASA, including advocates for environmental, clean energy, low-income communities, non-regulated power producers, businesses, and community interests. The Subcommittee engaged over the course of numerous meetings between October 2018 and December 2022, which are summarized in Figure 1.2 of the GMP. The GMP reflects stakeholder input on multiple topics, including the Distribution Study process and assumptions, time varying rate ("TVR") interests, and a variety of inputs for the BCA assumptions. Stakeholder input also identified several topics now discussed in greater detail in the GMP, such as the DER forecast assumptions to meet the Climate Mandates, modeling used to determine the difference in infrastructure needed with and without grid modernization, impacts of offshore wind on the GMP analysis, and the strategy regarding energy storage.

Q. At a high level, what is the first step proposed by the Company's GMP?

A. The Company's GMP goals can be thought of as a pyramid, where each layer of grid modernization builds upon the previous layer. The first step of this pyramid requires digitizing the physical assets by equipping them with remote monitoring and control features. To accomplish this, communication and remote control is added to physical devices such as capacitor banks, reclosers, meters and DER.

Q. Are these the same physical assets addressed in the Company's November 2022 AMF filing?

A. Not entirely; however, the assets are integrated. The AMF Business Case proposed digitizing Rhode Island Energy's electric meter assets. This GMP proposes to digitize key distribution assets and DER. That said, integrating the granular information provided by the AMF meters with the physical assets the Company proposes to digitize in this GMP will enhance the grid modernization capabilities. Both the AMF meters included in the AMF filing and GMP devices discussed in the GMP are components of the physical layer of the GMP pyramid.

Q. Why is digitizing the physical assets the first step in the Company's GMP?

A. The distribution system components must become more visible in real time so grid operators are aware of DER presence and its characteristics, such as rated capacity and power imports or exports over time. DER must also be controllable so their operation can be managed to leverage positive and minimize negative impacts to the grid while optimizing the benefits to DER-owning customers and to other customers. Visibility and controllability are prerequisites for totally integrating DER into the grid to realize its full potential.

Q. Please provide a general description of the Foundational Investments proposed in the GMP.

A. The Foundational Investments address the physical layer of the grid modernization pyramid and include a portfolio of software, communication, and advanced field devices that work together and are enhanced with AMF. This integrated technology portfolio requires a multi-year investment and must be implemented now for the continued safe and reliable operations of current conditions and to enable the Climate Mandates. The Foundational Investments are described in Section 6 of the GMP within the context of the GMP Roadmap. The Foundational Investments enable the Grid Modernization alternative discussed in the Distribution Study and provide the basis for costs in the BCA. Based upon the BCA and Distribution Study results, the Foundational Investments are considered “no regrets “investments, in that they are beneficial for any future DER adoption scenario and will provide flexibility to operate reliably and safely while addressing inevitable change and uncertainty.

Q. What benefits does the Company expect to realize from the Foundational Investments?

A. The Foundational Investments will provide numerous benefits to the electric distribution system. First, the Foundational Investments 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.

Second, the Distribution Study discussed below demonstrates that the Company can significantly avoid transmission and distribution infrastructure in the future by using grid modernization technology and functionality. For example, demand on individual feeders can be shifted through remote sectionalizing; voltage can be controlled and optimized; load can be shifted using TVR, and DER Monitor/Manage can be used to manage thermal loading and reduce curtailment. Thus, the Foundational Investments will enable the development of the transmission and distribution system to meet future needs at the lowest cost.

Third, the Foundational Investments are expected to reverse the Company's current trend of declining reliability due to the implementation of Fault Location Isolation and Service Restoration ("FLISR"). Furthermore, the added visibility and situational awareness of the distribution system will provide better information for crews to respond to outages faster, which will greatly enhance storm restoration.

Fourth, the Foundational Investments will optimize DER energy production. Without grid modernization investments, the Company would need to curtail renewable DG. The Foundational Investments reduce DG curtailment using the DER Monitor/Manage functionality.

Fifth, the Foundational Investments are expected to reduce operations and maintenance expenses from items such as dispatching efficiencies, avoided truck rolls, and avoided telecommunications fees.

Finally, the Foundational Investments will reduce peak demand and energy costs through TVR, Volt VAR Optimization ("VVO"), DER Monitor/Manage, and targeted demand response. These initiatives will allow the Company to avoid infrastructure costs and reduce ISO-New England ("ISO-NE") market costs for capacity, energy, and ancillary services.

Q. Describe generally the Future-Term Investments that are identified in the GMP.

A. The Future-Term Investments, covering years 2029-2042, will extend the Foundational Investments to leverage advanced grid technologies that can incrementally evolve over time commensurate with future DER adoption. These include investments in energy storage integration, more integrated DER and advanced incentive mechanisms to meet changing operational needs and customer needs, and the requirements of the Climate Mandates, all while maintaining safety and reliability.

Q. How will the Company's recommended investments help Rhode Island achieve the Climate Mandates?

A. Achieving the Climate Mandates requires facilitating DER adoption. Grid modernization investments will help reduce the costs and other barriers to interconnecting new DER in Rhode Island, which, in turn, will drive more DER adoption and investment in the State. Without grid modernization, the electric distribution system will become a roadblock to achieving the Climate Mandates. The legacy grid will slow the rate of DER adoption, make it more costly to implement electric vehicle ("EV") charging infrastructure, and limit the benefits customers can receive from future DER and energy efficiency programs.

Q. What do the data show regarding the Company's reliability performance in recent years?

A. Evidence suggests that the Company's reliability performance trend has declined over the last decade. Although the Company has met its regulatory reliability performance targets, as measured by the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"), it lags behind its peers and PPL Electric. Figures 1.7 through 1.10 in the GMP capture these trends.

Q. How will the Company's reliability performance improve with GMP?

A. The Company expects that the GMP Foundational Investments will stop Rhode Island Energy's reliability performance decline and begin to improve reliability. The GMP recommends investing in FLISR as part of its Foundational Investments, including the targeted deployment Advanced Reclosers deployed in conjunction with Advanced Distribution Management Systems ("ADMS"). Rhode Island Energy forecasts that the Company's SAIFI will improve by up to 30 percent and the Company's Customers Experiencing Multiple Interruptions ("CEMI") performance, which is a metric of how many customers experience multiple interruptions, also will improve.

PPL Electric was 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 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. From 2013 to 2016, while Rhode Island Energy's SAIFI performance decreased by five percent, PPL Electric's SAIFI improved by 22 percent. These gains are partially attributed to a system-wide FLISR deployment that uses ADMS, giving the Company confidence in its improvement predictions regarding Rhode Island Energy's reliability performance following these Foundational Investments.

V. <u>Current State of the Electric Grid</u>

Q. Explain the differences between the legacy distribution system and the "modern-day" grid.

A. The existing distribution system was designed to operate as a radial, one-way power flow system. Although some modifications have been made to accommodate DER, the fundamental design, protection, control, and operation have assumed that power was flowing from the generation source to the load. Thus, when faults occur on a distribution feeder (e.g., lightning strike, tree in line, broken cross-arm) the substation relays detect the fault, customers call in their outages, and crews are dispatched to investigate, manually isolate, and make repairs. Although the traditional electric power system has served utility customers well for decades, the new demands on the electric grid from technology advances and increased customer adoption of DER have created a two-way electric power system 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 only points of delivery. Customers can export electricity back to the grid and, if eligible, participate in net metering or the Renewable Energy Growth Program. Moreover, many customers are beginning to expect their "smart appliances" or "smart homes" to communicate with the utility so they can better manage their energy use. The emerging characteristics of a modern-day grid require 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.

Q. What grid modernization activities does the Company currently have underway?

A. Pursuant to the ASA, the Company undertook a limited initial set of grid modernization investments, including development of an AMF Business Case, maintenance of a System Data Portal, GIS data enhancements, including upgrades to accommodate new asset types, equipment and data attributes and additional tools to manage data quality, ADMS basic training and data development, remote terminal unit separation work, underlying information technology ("IT") infrastructure assessment, cyber security, and telecommunications work.

Additionally, the Company has deployed advanced field devices and Volt Var Optimization/Conservation Voltage Reduction ("VVO/CVR") on select feeders over the last three to five years.

The Foundational Investments proposed in the GMP will build upon this initial work.

Q. What challenges does the Company face today from DER interconnections?

A. Over the last few years, Rhode Island has seen a large increase in the number of applications for solar DG, increasing levels of EV and electric heat pump ("EHP") adoption, and broader participation and interest in opportunities to lower electric bills and/or take advantage of new revenue streams. The areas of Rhode Island with available land for DG development, however, often do not have electrical systems with available hosting capacity or are not robust enough to interconnect larger DG sites. The resulting issues often include voltage, power quality, and protection coordination. System modifications, including substation upgrades, line reconductoring, advanced control and monitoring, and advanced protection schemes, are required to maintain compliance obligations. The lack of hosting capacity throughout much of Rhode Island means that costly system upgrades will be necessary for interconnecting most new DG projects.

Q. Do these challenges affect the ability of DG proposals to move forward?

A. Yes, in many instances. Interconnection costs have increased dramatically over the last few years for both smaller-scale and large-scale DG projects. Additionally, the high saturation of current and proposed DER, 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. These studies add time, complexity, and costs to the interconnection process, the burdens of which many customers and developers cannot bear. Currently, between 50 and 70 percent of DG applications are cancelled prior to completing the project due to issues with local permitting approval, getting proper financing, and high site costs, including utility system upgrades necessary for interconnection.

Q. Do increases in DER interconnections affect reliability and safety?

A. Yes. Reliability and safety impacts resulting from DER-caused distribution system issues can include overloading of conductors, 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 the mix of rotating and inverter-based generation with different islanding algorithms; protection coordination concerns, specifically desensitization of ground fault protection; and exceeding equipment short circuit ratings.

Q. What operating limitations does the Company experience with its existing distribution system?

A. Current operating limitations include 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; and inability to properly protect the distribution system with changing topology. Most of these operational limitations are present at times on some areas of the electric distribution system today, and many of these limitations will be exacerbated by the continual increase in DER interconnections.

Q. What are the implications of operating a modern-day grid without the visibility and control that the GMP investments afford to the Company?

A. Because the Company does not have visibility or situational awareness of the distribution system today, it experiences challenges on the electric distribution system, especially where there is significant DER penetration. Because few distribution feeders are remotely monitored or controlled, there is unrecognized backflow, over and under voltages, thermal overloads, and hidden load, which can cause reliability, safety, and incorrect operating issues from the lack of system visibility.

As a result, except for large interconnections that have a dedicated recloser at the point of interconnection, 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, Rhode Island Energy is generally unaware of the affect it may be having on other customers and equipment in the area.

Q. How will the GMP facilitate DER interconnection?

A. Currently, 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 would be necessary if more granular information was available. Many DER projects are not pursued in Rhode Island because of these issues, making it more difficult to meet the Climate Mandates.

Without the needed visibility, situational awareness, and control of the distribution system that AMF and GMP functionality and equipment provide, the Company's only method of controlling the operational issues defined above (e.g., voltage violations, thermal overloads, back flow, relay and protection) is to perform interconnection studies to identify potential issues. Even with this careful attention to planning, however, without granular, real-time visibility, operators will need to perform unplanned DER curtailment to protect the system. Without the GMP investments, the need for 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.

With GMP deployment, 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 customers and enable the achievement of the State's clean energy goals.

Q. What do customers stand to gain from investing in GMP technologies?

A. 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.

With the 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.

Q. What are the risks customers face from operating a modern-day grid without the functionalities of grid modernization?

A. Customers face several different risks, including higher than necessary operations and maintenance cost, lengthy recovery time from storm outages and other major events, limited interconnection options, and curtailment of DER, generally. In addition, without the functionalities of grid modernization, Rhode Island customers will not enjoy the full clean energy benefits intended from the Climate Mandates.

VI. <u>Functionalities Needed to Transform the Grid</u>

Q. What functionalities are necessary for a successful transformation from the legacy electric distribution system to the modern-day grid?

A. The Company has identified two tiers of functionalities necessary to meet operational needs, customer needs, and Climate Mandate needs of a modern-day grid. Tier 1 includes Customer Enablement, System Monitoring and Control, and System Optimization. These capabilities generally represent the physical layer in the grid modernization pyramid described earlier. Tier 2 includes IT Infrastructure, Cyber Services, Data Acquisition, System Modeling, and Analytics. Tier 2 functionalities may not have direct benefit impacts themselves, but they are necessary to enable most, if not all, benefit impacts presented by the Tier 1 functionalities. These capabilities represent the upper layers in the grid modernization pyramid.

Q. What is the Customer Enablement functionality?

A. Customer Enablement is a multi-layered functionality intended to give customers better and more-timely information on which to base their energy choices by providing them with information about their historical usage, available advanced pricing, real-time remote metering, and distribution system data. The Customer Enablement functionality discussed in the GMP was also discussed at length in the AMF Business Case.

Q. What are the anticipated benefits of Customer Enablement?

A. Customer Enablement will reduce system capacity requirements and customer energy use by providing enhanced insights (such as high usage alerts) from more granular, timely energy usage data. It also will provide customers with improved energy usage information and access to third-party service providers, empowering customers to better understand and prioritize among solutions to best manage their energy usage and costs. Customer Enablement allows for innovative demand-side management programs. It also will likely reduce average outage duration for customers due to improved outage notification. Finally, this functionality will improve the selection of DER locations by showing customers and DER providers where the most cost-effective interconnection locations are on the distribution system.

Q. Please describe the Observability (Monitoring & Sensing) functionality and its anticipated benefits.

A. The Observability (Monitoring & Sensing) functionality enables system planners and operators to design and operate the distribution system in a more flexible and efficient manner. This functionality is foundational to supporting all other key functionalities.

Q. Please describe the Power Quality Management functionality and its benefits.

A. Power Quality Management is the process of ensuring proper power form, including mitigation of voltage transients and waveform distortions. This functionality reduces system capacity requirements and customer energy use by enabling the system operator to manage the voltage impacts of renewable DER and to operate distribution feeders at lower overall voltages, reducing electricity consumption and peak demand from customer appliances.

Q. Please describe the Distribution Grid Control functionality and its anticipated benefits.

A. This functionality provides the ability to manage distribution power flows while maintaining distribution operational parameters within specific operating ranges through dynamic management of grid devices and DER. It enables the system operator to rearrange the distribution feeders and maximize the load-to-generation balance to avoid thermal issues.

Q. Please describe the Grid Optimization functionality and its anticipated benefits.

A. Grid Optimization is an analytical functionality integrated with decision support systems and operational controls to optimize grid reliability, resilience, efficiency, and hosting capacity. It enables the system operator to control power flows autonomously or remotely rather than investing in traditional "wires" solutions.

Q. Please describe the Reliability Management functionality and its anticipated benefits.

A. 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.

Q. Please describe the DER Management functionality and its anticipated benefits.

A. The DER Management functionality provides for real-time monitoring and coordinating of DERs to optimize network operations, maintain system reliability and resilience, and provide more cost-effective solutions for viable DER interconnections. This functionality will reduce DG curtailment by allowing specific management of DERs rather than relying on seasonal curtailment to avoid thermal or voltage constraints.

Q. What are the Tier 2 functionalities?

A. The Tier 2 functionalities are Distribution System Representation (Network Models), Operational Analysis & Forecasting, Operational Information Management, Cyber Security, and Operational Telecommunications. These functionalities support all other key functionalities.

Q. What is Distribution System Representation?

A. Distribution System Representation is a functionality that provides a topological model of the physical distribution system itself, including customer and DER connectivity—with asset characteristics—that is capable of reflecting dynamic changes to the state of the system.

Q. What is Operational Analysis and Forecasting?

A. The Operational Analysis and Forecasting functionality allows 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.

Q. What is Operational Information Management?

A. Similar to Operational Analysis and Forecasting, Operational Information Management involves recording, processing, and storing operational data that the Company relies on to support its operational business functions and related processes.

Q. What is the Cyber Security functionality?

A. The Cyber Security functionality involves protecting the Company's 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, malpractice by operators, or deviation from secure procedures.

Q. What is Communications?

A. Communications consists of the communication protocols, technologies, and assets that are present between operating centers and substations, and it extends into the field to controllable grid devices (e.g., switches, capacitor banks, protective devices), meters and DER on local feeders. Operational communications need to maintain highly reliable connectivity under both normal and degraded system operating conditions (e.g., electrical noise, equipment failure, and physical attacks).

Q. How will the GMP functionalities impact the Company's load management initiatives and programs?

A. The investments in GMP functionalities and load management initiatives and programs will affect each other over time. The more granular data obtained from the GMP investments will allow the Company to more effectively progress residential and small commercial DER market-facing or customer-facing programs. At the same time, the pace, scale, and effectiveness of DER market-facing and customer-facing load management programs will impact the effectiveness of the GMP solutions.

Q. Which load management initiatives and programs does the Company expect to impact the evolution of the GMP functionalities?

A. There are currently five load management programs that the Company expects will impact the evolution of the GMP: energy efficiency, demand response, energy storage, transportation, and heat electrification. Section 3.5 of the GMP discusses the interaction of these load management programs with the GMP.

Q. What GMP solutions does the Company propose to achieve the Tier 1 and Tier 2 functionalities discussed above?

A. The Company proposes a series of GMP solutions to achieve the Tier 1 and Tier 2 functionalities, which fall into five integrated facets: (1) a network of AMF electric meters and DER Monitor/Manage devices; (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) micro-processor 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. To achieve safe and reliable operation of the Company's distribution system will require full integration of all the proposed solutions. Figure 4.3 of the GMP defines each of the proposed solutions and their function. Section 6 and the Deployment Plan, included as Attachment H, contain detailed descriptions of each.

VII. <u>Distribution Study Scope and Results</u>

Q. At a high level, what is the Distribution Study that Rhode Island Energy performed?

A. The Distribution Study was a statewide analysis of the electric system to determine the most efficient investment plan to meet the State's Climate Mandates while also ensuring safety and reliability. The scope of the study included analysis of sub-transmission and distribution systems. Rhode Island Energy also performed a separate bulk transmission study using the results from the Distribution Study to determine the impacts to the bulk system.

Q. Why did Rhode Island Energy perform the Distribution Study?

A. Rhode Island Energy performed the Distribution Study to determine the avoided costs of distribution system infrastructure and other benefits that grid modernization would provide.

Q. What is the purpose of the Distribution Study?

A. The major purpose of the Distribution Study was to ensure that the Company's future infrastructure improvements are prudent and viable given a range of uncertainties with load and generation in the future. The goal was to ensure that the distribution investments are best prepared for the variety of possible futures at the lowest cost and greatest benefits.

Q. What did the Distribution Study use as a "base case"?

A. The "base case" model for this study started with the Company's Area Planning infrastructure models. The Company then applied load and generation forecasts through 2050 (forecasting for milestone years of 2030, 2040, and 2050) that varied throughout the day, the seasons, and over the years reflecting changes in load shape and demand resulting from the forecast.

This approach is a fundamental change from previous planning efforts, which focused their analysis on static power flow at static times. To enable a time-based planning approach, the Company created a DER forecast through 2050 to meet the Climate Mandates.

The models were set up with this forecast to analyze every hour of the year (8,760 hours) across tens of thousands of nodes to determine the loading and voltage stress points of the distribution system. The summer and winter load and generation peaks were studied in detail. This 8,760-hour load cycle analysis identified the worst peak load demand and worst peak generation operating hours and load conditions. The Distribution Study identified thermal overload and voltage violations that would occur during those conditions if no additional solutions were deployed. These extremes were later modeled on the bulk transmission system for subsequent analysis.

Q. What additional solutions did the Distribution Study consider to address the identified thermal overload and voltage violations?

A. The Distribution Study considered two alternative solutions to mitigate the voltage and thermal violations, the "No Grid Modernization" alternative and the "Grid Modernization" alternative.

Q. What was the "No Grid Modernization" alternative?

A. The "No Grid Modernization" alternative identified sub-transmission and distribution upgrades necessary to obviate the identified violations in each area in addition to the Area Study upgrades modeled in the base case. The Distribution Study also identified the amount of energy that would have to be curtailed each year using disconnects at large DER sites without the benefit of grid modernization technology.

Q. What was the Grid Modernization alternative?

A. The "Grid Modernization" alternative modeled grid modernization functionality and equipment and its ability to mitigate voltage and thermal issues. It then determined the reduced amount of sub-transmission and distribution upgrades needed to obviate remaining violations in each area. The Distribution Study identified the reduced amount of DER curtailment resulting from proposed grid modernization functionality. The Distribution Study then fed these results back into the original Area Study plan to determine if any of the originally identified upgrades would need to be modified or eliminated to ensure consistency with future grid modernization conditions and long-term usefulness. This approach was important to ensure that the grid modernization infrastructure would not build upon retiring assets or duplicate planned assets and also to ensure that the Area Planning Studies would sufficiently support the grid modernization needs.

Q. In developing the base case, how does the Distribution Study envision future high load and high generation periods will change during the study period?

A. The combined impact of electric heating and electric vehicles 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 Company no longer solely focuses on peak and light load quantities for forecasting; instead, the Company focuses on forecasting by considering the individual load cycle contributions and the peaks created by each of the individual load cycles.

Q. What other forecasting assumptions does the Distribution Study make?

A. The Distribution Study makes forecasting assumptions relating to EV usage, EHP usage, increases in solar photovoltaic ("PV") allocation, and wind energy generation.

Q. What is the basis for the Company's forecasting assumptions?

A. The Company assumes that the State will meet the required Climate Mandates. Doing so will require the adoption of a combination of solar generation, wind energy production, EV usage, and EHP conversion. The forecasts described in the Distribution Study represent the levels of adoption required to meet the Climate Mandates.

Q. How does the Company forecast EV usage in Rhode Island during the study period?

A. The Company anticipates that in order to reach the State's Climate Mandates, EV usage will need to increase dramatically. There are currently between 4,000 and 5,000 EVs in Rhode Island. This number 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 in the State would be electric by 2050.

To allocate the Company's EV charging forecast to the distribution network for the 2030/40/50 study years, the Company allocated EV vehicles to existing customer load points, or residences. By 2030 it was assumed that 22 percent of residences would have one EV. By 2040, all residences are assumed to have one EV, with approximately 70 percent having two EVs. By 2050 it was assumed that 100 percent of residences would have two EVs.

Q. How does the Company forecast that EHP usage will change in Rhode Island during the study period?

A. Again, the Company expects that the use of EHP will increase dramatically. Currently, there are 4,000 to 6,000 homes heated with EHP, while there are approximately 400,000 businesses and residences heated with gas/oil fuel. The number of homes/businesses converting from gas/oil to efficient EHP for heating and air conditioning is projected to increase to 51,000 by 2030, 325,000 by 2040, and 400,000 by 2050.

Q. How will the increase of EHP in Rhode Island impact Rhode Island Energy's electrical distribution system?

A. The conversion to EHP 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 such that the winter peak will become the highest peak demand of the year. The overall conversion to EHP is expected to increase the annual energy requirements for Rhode Island by 2,200 gigawatt hours ("GWh") by 2050.

Q. How does the Company forecast that solar PV will change in Rhode Island during the study period?

A. PV nameplate capacity will need to increase to meet the State's Climate Mandates. There is currently about 504 MW of solar PV connected to the electric distribution system and over 600 MW in the interconnection queue. This existing PV provides an annual energy supply of approximately 618,000 megawatt hours ("MWh"). PV nameplate capacity will need to increase to 1,800 MW by 2030, 3,700 MW by 2040, and 5,300 MW by 2050. 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.

Q. How does the Company forecast that wind generation will change in Rhode Island during the study period?

A. Onshore and offshore wind energy generation will need to increase to meet the State's Climate Mandates. Rhode Island currently has 50 MW of onshore wind and 30 MW of offshore wind. Another offshore wind farm is currently undergoing regulatory approval, and upon approval and interconnection it will have 400 MW allocated to Rhode Island. The existing wind generation provides an annual energy supply to the State of approximately 165,000 MWh. Onshore and offshore wind will need to increase respectively to 100/900 MW by 2030, 115/1,035 MW by 2040, and 145/1,300 MW by 2050.

Q. You indicated earlier that you evaluated the Company's overall forecast using both "No Grid Modernization" and "Grid Modernization" alternatives. What types of investments were included in the "No Grid Modernization" alternative?

A. The "No Grid Modernization" alternative used only traditional transmission and distribution investments to mitigate the thermal loading and voltage violations identified. These included phase balancing, re-conductoring feeders, new feeder circuits with new substation bays, new transformers, new transmission and distribution substations, reconductoring sub-transmission lines, new sub-transmission lines with new substation bays, and traditional reclosers, capacitor banks, and voltage regulators.

Q. What types of investments were included in the "Grid Modernization" alternative?

A. The "Grid Modernization" alternative included the investments proposed in this GMP, including state-of-the-art ADMS/Supervisory Control and Data Acquisition ("SCADA") functionality with FLISR, VVO/CVR, TVR/Critical Peak Pricing ("CPP") and locational Demand Response, and Distributed Energy Resources Management System ("DERMS") DER Monitor/Manage software; secure communications; AMF meters; and GMP advanced field devices. After accounting for these grid modernization functionalities, any required traditional investments were added to mitigate the violations identified. The intent was to determine whether the GMP could eliminate or defer traditional transmission and distribution investments and, if so, by how much.

Q. What was the Distribution Study result of implementing the "Grid Modernization" alternative?

A. The "Grid Modernization" alternative reduced the 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 necessary physical infrastructure upgrades also was greatly reduced compared to the "No Grid Modernization" case. The "Grid Modernization" alternative required less curtailment of DER interconnection due the DER Monitor/Manage functionality that is enabled by ADMS-DERMS.

Q. How did cost differ between the "No Grid Modernization" alternative and the "Grid Modernization" alternative?

A. The "Grid Modernization" alternative resulted in significantly lower transmission and distribution costs. Because grid modernization functionality provided visibility and situational awareness to the 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 transmission and distribution investment by 2050 was significantly less than in the "No Grid Modernization" alternative.

Q. What conclusions did the Distribution Study reach?

A. The Distribution Study concluded that the "Grid Modernization" alternative substantially reduces necessary infrastructure versus the "No Grid Modernization" alternative. Regardless of the specific location and size of the PV, wind generation, EV, and the EHP, the "Grid Modernization" alternative provides superior adaptability and agility in the face of all possible Climate Mandates futures.

Q. Does the GMP offer additional benefits beyond those identified in the Distribution Study?

A. Yes. There are several other GMP benefits in addition to avoided infrastructure cost and DER curtailment differences, including ISO-NE system capacity and energy savings;

reliability savings related to reduced outage time and faster restoration after storms and other outages; and reduced operations and maintenance ("O&M") cost related to operational efficiency gains from distribution system automation.

Q. Overall, how do the "No Grid Modernization" and "Grid Modernization" alternatives compare in the Distribution Study?

A. In short, the Distribution Study concludes that with the "No Grid Modernization" alternative there is an inability to monitor and control operational needs and maintain safety and reliability. In contrast, under the "Grid Modernization" alternative, there is full visibility and control of operational needs, as well as reduced outages and faster response times, resulting in reduced O&M costs. With respect to customer needs, the "No Grid Modernization" alternative results in higher capacity and energy costs, high transmission and distribution costs, and an inability to optimally use TVR rates. The "Grid Modernization" alternative, however, leads to lower energy costs, avoided transmission and distribution costs, and an ability to use TVR/CPP/DR, among other benefits. Finally, with respect to the Climate Mandates, the "No Grid Modernization" alternative results in high DER curtailment and the Climate Mandates are not achievable, while the "Grid Modernization" alternative leads to minimal DER curtailment and would facilitate Rhode Island achieving its Climate Mandates.

Q. Did the Company perform any other studies of the Rhode Island Energy electric system?

A. Yes. In addition to analyzing the sub-transmission and distribution system, the Company performed a transmission planning study ("Transmission Study") to analyze the Rhode Island Energy bulk electric system impacts under the same 2030/2040/2050 conditions.

Q. What did the Transmission Study analyze?

A. The Transmission Study conducted a preliminary analysis of an additional 115-kV transmission line in Western Rhode Island. Three new substations were connected to the new line, and existing generation/load was transferred from area stations to the three new substations.

Q. What did the Transmission Study show?

A. The results of the Transmission Study identified several transmission line overloads. The Transmission Study also indicated that the expansion of the 115-kV system does offer the potential to further avoid transmission and distribution infrastructure cost because loading was reduced on multiple 115-kV circuits under peak load conditions.

Q. What are the recommendations from the Distribution Study and Transmission Study?

A. The results of the Distribution Study provide strong support for the Company's recommended approach to adopt the "Grid Modernization" alternative, including the Foundational Investments described in the GMP. 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 Distribution Study and the Transmission Study to determine if converting a portion of the sub-transmission system to a higher voltage level and 115 kV system 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.

VIII. GMP Roadmap With DER Management Functionality

Q. What is the GMP Roadmap?

A. The GMP Roadmap is a sequenced progression of grid modernization investments that will establish fundamental grid modernization capability using highly integrated solutions. The GMP Roadmap presents the near-term solutions as the Foundational Investments. These Foundational Investments can be built upon to deliver future-term solutions after 2028 as needed, based upon the rate of the incremental DER penetration and future EV adoption rates. The GMP Roadmap assumes that ADMS Basic[4] functionality will be available in May 2024 and that AMF functionality will be available beginning in 2026. These functionalities are necessary for operation of the Foundational Investments. Given the urgent operational need for the Foundational Investments, the GMP Roadmap forecasts to have their deployment significantly completed by the end of 2028.

Q. Why is ADMS Basic important to the GMP Roadmap?

A. ADMS is central to the linkage between AMF and GMP. Because ADMS Basic includes FLISR and granular AMF meter data integration, it results in early benefits that are closely timed with the installation of advanced field devices. The ability to recognize the benefits in the early years of the BCA analysis contributes to the strong GMP Net Present Value ("NPV") results.

[4] 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 Service Company. As part of the Acquisition approval, PPL committed to forego the potential recovery of any and all 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 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 GMP, the defined term ADMS Basic refers specifically to the software that PPL is providing to Rhode Island Energy as part of the transition.

Q. How will the GMP Roadmap enable customers to have greater understanding, choice, and control of their electricity consumption in the near and long term?

A. Customers gain greater understanding, choice and control through the Customer Enablement aspect of the GMP Roadmap, which is largely enabled with AMF. Granular AMF meter data will be integrated with the ADMS Basic/Outage Management System as each AMF meter is exchanged starting in the middle of 2025. Figure 6.3 in the GMP overlays the AMF implementation timeline with the GMP timeline to display the GMP investments that are planned through the proposed AMF implementation and illustrate how the two deployments are coordinated. As a result, customers will be empowered with enhanced understanding, choice, and control over their electricity consumption, to help them reduce energy bills through greater insights about their energy cost drivers, personal usage, and new product and service offerings. The GMP Roadmap contemplates TVR going into effect in 2026 after the AMF meters have been fully installed and pending approval of a separate filing for a proposed rate structure.

Q. How does the GMP Roadmap address operational systems and applications that will support GMP-enabled functionalities?

A. A significant amount of IT planning, development, and system integration is required to achieve various GMP-enabled functionalities. Rhode Island Energy plans to align grid modernization systems to mirror the current grid modernization architecture and functions that PPL Electric has used in Pennsylvania as closely as possible and to make those functionalities available no later than May 2024, when Rhode Island Energy will exit the Transition Services Agreement with National Grid Service Company. The GMP systems will include ADMS Basic and distribution-specific SCADA ("DSCADA"). This will allow for the integration of the DSCADA equipment status and device data to improve situational awareness, outage analysis and solution accuracy and granularity with advanced applications.

Additionally, because ADMS accepts real-time information from advanced field devices and granular AMF meter information, the timing of ADMS functionality has been closely coordinated with Advanced Field Device installation assumptions and the timing of benefits for FLISR, VVO, and DER Monitor/Manage.

Q. How will the GMP Roadmap utilize ADMS in the near and long term?

A. In the near term, ADMS will include systems and advanced applications that will enable control center operators to make more optimal system configuration decisions based on the actual constraints of the electric distribution system via a real-time network model. In the long term, as more data is available from physical devices and as the ADMS platform is advanced, it will phase-in the functionality as described in Section 6.3 of the GMP and graphically displayed in Figure 6.6 of the GMP.

Q. How will the GMP Roadmap use VVO?

A. VVO is a near-term functionality. Benefits start accumulating in 2026 and incrementally build over the remaining five years as smart capacitors and regulators are installed in the field and after the ADMS-VVO application is available. As discussed in the BCA, 20 percent 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.

Q. How will the GMP Roadmap use FLISR in the near and long term?

A. In the near term, the implementation of ADMS Basic will enable management of FLISR while preparing advanced ADMS applications like DERMS. Benefits from FLISR start accumulating in the BCA beginning in 2024.

Q. How will the GMP Roadmap use Mobile Dispatch in the near and long term?

A. ADMS-based Mobile Dispatch 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 the near term, the proposed Mobile Dispatch pilot project includes a limited deployment of mobile dispatch capabilities to select field personnel. In the long term, learnings from the pilot project will be applied toward developing the de-centralized process flows and requirements for a full deployment, which is expected to improve outage restoration times, the efficiency and accuracy of restoration efforts, and worker safety.

Q. How will the GMP Roadmap utilize IT infrastructure in the near and long term?

A. The Company will place IT Infrastructure in service incrementally as components of the GMP are completed. 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 cyber security a necessary capability to operate a safe, reliable, and cost-effective electric distribution system, especially as more intelligent devices are interconnected and integrated with utility operations.

Q. How will the GMP Roadmap utilize DER Monitor/Manage in the near and long term?

A. DER Monitor / Manage is important to the success of the GMP. The Company is assessing the legal and regulatory approvals necessary to permit DER Monitor/Manage and will make a separate filing for any such approvals, including any tariff changes to require new DER interconnections to 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 DER. The Company has included DER Monitor/Manage in the Foundational Investments where installations are assumed to start in 2026. The Company plans to install DER Monitor/Manage as DER incrementally interconnects over the long term.

Q. Why is DER Monitor/Manage important to the success of the GMP?

A. There are several reasons that DER Monitor/Manage is important to GMP success. First, the Distribution Study and corresponding BCA quantifies reduced DER curtailment with DER Monitor/Manage functionality. This resulted in an average renewable DG seasonal curtailment of 17.7 percent annually with the "No Grid Modernization" alternative in 2030 compared to 0.7 percent with the "Grid Modernization" alternative. Part of this reduction in curtailment resulted from energy shifting and battery energy storage system management, which DER Monitor/Manage enables. DER can be ramped down rather than completely curtailed. This maximizes renewable energy production, optimizes transmission and distribution infrastructure, avoids new infrastructure costs, improves the customer experience, improves power quality, and increases hosting capacity. Second, with DER Monitor/Manage, the amount of DER that can be safely and reliably interconnected with the electric distribution system can be increased significantly. Power factor management can increase the hosting capacity of the Company's electric distribution system, which will enable more DER without the need for system upgrades. Safety benefits will result from operators being able to better determine the output of impacted DER during a disturbance or an outage to safely perform system restoration without violating any equipment constraints. Third, power quality can be improved at customer sites by leveraging DER voltage support functions, potentially avoiding the need to deploy traditional voltage regulation infrastructure. Fourth, the stability and reliability of the system will be improved using smart inverters with IEEE 1547-2018 capabilities, and DER will have the ability to "ride through" low and high voltage and frequency events. Finally, with real time DER visibility to DER generation output, the issue of "load masking" or "hidden load' will be avoided. In short, DER Monitor/Manage will make DER a beneficial distribution asset that is fully integrated into the electric distribution system operations.

Q. How does the GMP Roadmap address advanced field devices for the near-term?

A. Solutions for the near-term Foundational Investments include advanced field devices such as capacitors, regulators, reclosers and microprocessor relays. In the near-term smart capacitors and regulators with advanced controls will be deployed that provide voltage and reactive power control to enable management of voltage along the distribution feeder within required American National Standards Institute ("ANSI") voltage standards. Voltage levels can be managed within required ANSI voltage standards and optimized using the ADMS-VVO application with the inputs of the smart capacitors, regulators and granular voltage data from AMF meters.

In addition, the GMP includes near-term investments in advanced reclosers used to isolate customer outages due to temporary faults via automatic sectionalizing and restoration. Advanced recloser installations start as soon as 2023 and work in conjunction with ADMS-FLISR. Corresponding reliability improvements are expected to start in 2024.

Q. How does the GMP Roadmap address advanced field devices for the future-term?

A. One of the ways the GMP Roadmap addresses advanced field device for the future-term is through adaptive protection. ADMS software will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices and ensure worker safety and the reliable operation of the grid. The first phase of the ADMS adaptive protection functionality is planned to be available in 2027, and the second phase is scheduled in 2029.

Q. What investments does the Company plan to make in the communications network?

A. The Foundational Investments include development of a communications network that includes a Company-owned fiber backhaul. The grid modernization communications capability is achieved with several components, including but not limited to, the Company-owned wireless radio frequencies ("RF") communications network that the Company proposed in its AMF Business Case, leased cellular communications to the Advanced Field Devices, and the proposed fiber backhaul communication system interfacing with substation infrastructure. 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" that 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 network's primary function will be to enable secure and efficient two-way communication of information and data between the Rhode Island Energy ADMS and other head-end IT systems with new or planned intelligent advanced field devices.

Q. Does the GMP Roadmap address any other future solutions?

A. Yes, there are a number of other future solutions contemplated in the GMP Roadmap. For example, the future-term vision is for energy storage and/or EV charging to have automated controls 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.

IX. Risk Mitigation, Deployment, and Accountability

Q. How does the GMP manage risks of redundancy, obsolescence, and uncertainty?

A. The GMP uses a wide range of methodologies to manage risks of redundancy, obsolescence, and uncertainty. 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 in accordance with the framework that the PUC adopted in Docket No. 4600 (the "Docket 4600 Framework")[5] that includes sensitivities, and developed a portfolio of Foundational Investments that that are malleable and can be modified through future regulatory review based on actual DER adoption rates and system needs.

Q. What steps has Rhode Island Energy taken to prepare for all future state scenarios?

A. Most notably, the Company performed the state-of-the-art Distribution Study described earlier. The Distribution Study creates a framework for understanding the capabilities required to achieve the Climate Mandates and the range of alternatives available to build and operate a corresponding safe and reliable modern-day grid. This GMP proposes investments that will be necessary under any future state – and under any range and pace of DER adoption – making it the least-risk approach to moving forward in the face of uncertainty. At the same time, the GMP Roadmap provides for sequencing and pacing near-term and future-term solutions to match actual conditions as they evolve.

Q. How does PPL's experience help mitigate risk?

[5] *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).

A. As discussed in the Pre-Filed Direct testimony of Company Witness David J. Bonenberger, PPL is an innovator, industry leader, and early adopter of grid modernization technologies. Rhode Island Energy will benefit from PPL platforms, systems, and expertise already in operation that will improve the efficiency of implementing the planned and purposeful rollout of the GMP.

Q. How does the GMP's BCA mitigate risk and foster accountability?

A. The Company developed a quantitative BCA for the GMP 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. As we discuss below, the GMP has a positive BCA under any of the future states evaluated. That said, the Company is not seeking approval of specific GMP investments or corresponding cost recovery through this filing. Rather, the Company will seek approval of, and cost recovery for, the initial GMP investments in the FY 2024 Electric ISR Plan filing. Any subsequent GMP investments will be proposed, and cost recovery will be sought, through subsequent ISR filings. This means that the Company will have to demonstrate the reasonableness and prudency of the GMP investments in the future when the Company seeks to make them. This will foster accountability because the Company must ensure that the GMP continues to align with the evolving future state conditions. It also mitigates risk to customers because GMP investments will not be proposed until they become necessary for safe and reliable operations.

Q. How does Rhode Island Energy plan to utilize the GMP Deployment Plan as part of its risk management approach?

A. The GMP Deployment Plan ensures that the GMP will be successfully developed and implemented over the next decade and beyond. It provides a summary of the approach, supply chain/vendors, project governance, benefits, costs, and the GMP solutions portfolio. The GMP Deployment Plan is included as Attachment H of the GMP.

Q. How will Rhode Island Energy ensure data privacy and cyber security while introducing new grid-connected technologies?

A. Rhode Island Energy has developed 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 the GMP. The Company's commitment to stewarding GMP data is memorialized through its Cybersecurity, Data Privacy and Data Governance Plan ("Data Governance Plan"), attached to the GMP as Attachment K.

Q. How does Rhode Island Energy plan to report on metrics?

A. The Company proposes to monitor and report on metrics on an annual basis throughout the time horizon of the GMP to ensure timely and effective solutions are deployed and benefits realized, including DER metrics, implementation metrics, and performance metrics.

Q. What is the Company's plan for tracking DER metrics?

A. The Company plans to monitor the following metrics annually so that the GMP can adapt appropriately to the evolving environment: (1) DER Interconnections, including wind DG, solar DG, energy storage, and EV and EHP load growth through the annual planning process and (2) Dispatchable DR, including Customer DR Programs, non-wires alternatives ("NWA") Projects, and energy storage.

Q. What is the Company's plan for monitoring deployment metrics?

A. The Company plans to track the deployment progress of GMP investments by monitoring the following metrics annually for the Foundational Investments: (1) advanced field devices (AMF, advanced capacitors and regulators, advanced reclosers, and microprocessor relays) and the following information for those devices: the number of devices installed and in-service, the number of feeders covered, the cost for deployment, and the deviation between actual and planned deployment; (2) control center and back office, including ADMS core functionality and underlying IT infrastructure; (3) telecommunications, including the number of communication devices, or nodes, or miles of fiber installed; the cost for deployment; and the deviation between actual and planned deployment; and (4) applications (FLISR, VVO, and DERMS) and the following information for the applications: the number of feeders commissioned, the cost for deployment, and the deviation between actual and planned deployment.

Q. What is the Company's plan for monitoring performance metrics?

A. The Company plans to track the performance of GMP investments by monitoring the following metrics annually during the Foundational Investments: (1) system-level impacts, including peak loading, minimum loading, load range, and load factor; and (2) modular ADMS optimizing applications as follows: VVO/CVR (energy savings, peak demand savings, loss reduction, and power factor improvement).

Q. What potential future policies, regulations and requirements are expected to impact the evolution of the GMP?

A. The GMP envisions that TVR will be a primary driver of load shifting through customer load management programs. The GMP also 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 grid, customers, DER developers, and society. 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 to allow Rhode Island Energy to provide such monitoring and management services. Additional details are presented in Attachment G to the GMP.

Q. How will Rhode Island Energy seek cost recovery of GMP investments?

A. As we have described, Rhode Island Energy intends to seek cost recovery of specific GMP investments through the annual Electric ISR Plan filings. Investments included in the Electric ISR Plan, however, are generally limited to the Company's capital investments, and many of the GMP investments include IT systems and other back-office systems that can be leveraged by PPL affiliates. Generally, these shared assets will be owned by PPL, and the costs for the Company's use of those systems will be accounted for through an allocated annual O&M rental expense. The Company expects to present the cost recovery of these, and other, O&M expenses in periodic multi-year rate case proceedings.

X. Benefit-Cost Analysis and Docket 4600 Framework

Q. What is the purpose of the BCA?

A. The purpose of the BCA is to demonstrate the benefits and costs of implementing the GMP across Rhode Island Energy's electric distribution service territory. Section 8 of the GMP presents the BCA in detail.

Q. Does the GMP address the Docket 4600 Framework and goals of a future electric system that the PUC adopted in Docket No. 4600?

A. Yes. Attachment I to the GMP discusses how the Company quantified the GMP functionalities and benefit impacts using the Docket 4600 Framework. Table 8.31 of the

GMP shows the alignment of the GMP benefit categories with the Docket 4600 Framework.

The GMP BCA uses the Docket 4600 Framework 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 4600 Framework.

Q. What approach did the Company take to developing the BCA?

A. The GMP BCA uses the Docket 4600 Framework to identify where grid modernization solutions contribute to specific cost or benefit categories. Where possible, these benefits are quantified. The benefits are evaluated over a 20-year period (2023-2042) and calculated in $Nominal and $2023 NPV. The Company also assessed benefits that could not be calculated. Care was taken to avoid double counting benefits that were included in the Company's AMF Business Case that is currently pending with the PUC in in Docket No. 22-49-EL.

The Company used several different analyses to develop the benefit estimates that will result from implementing investments included in the GMP. These include:

- a leading-edge, comprehensive Distribution Study to determine the avoided infrastructure cost;
- a load balancing analysis to determine the impact of grid modernization on the Company's load shape and also to determine the DER curtailment benefits of the grid modernization investments;
- a reliability/recloser analysis to calculate the benefits of reducing the frequency of outages using Reclosers/FLISR;
- VVO analysis; and
- System loss analysis.

The BCA also accounts for the Climate Mandates. Specifically, the DER, EV charging, and EHP forecasts are designed to meet those mandates.

Q. Please explain how the Company assessed the benefits for the GMP.

A. Section 8.3 of the GMP describes how the Company calculated the benefits for the BCA. In brief, benefits were estimated over a 20-year period, both in nominal values and in NPV. The Company placed the benefits 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 have an outage. Societal Savings include avoided costs that result from reducing the amount of CO_2 and NO_x in the air and improving public health. Both CO_2 and NO_x pollutants are created by producing electricity with fossil fuel generation. These pollutants create costs to society, such as climate impacts and health impacts, which are not included in the price of electricity. If electricity can be produced through non-carbon sources, such as wind and solar, these costs are avoided and therefore become a benefit of being able to produce more electricity from non-carbon renewables. For the purposes of estimating utility, customer, and societal benefits that are aligned with the "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. For the first GMP goal to give customers more energy choices and information, the benefit impact areas are as follows: improved customer choice and control; improved DER experience; and more equitable cost and benefit allocation. For the second goal of ensuring reliable, safe, clean, and affordable energy to benefit customers over the long term, the benefit impact areas are as follows: O&M savings; reduced customer energy use; reduced system capacity requirements; reduced outage frequency; and reduced outage restoration time. The third goal is to build a flexible grid to integrate more clean energy generation, and the benefit impact areas are avoided distribution system infrastructure cost and reduced DG curtailment.

Q. Please describe the expected quantified benefits from the GMP investments.

A. Over the 20-year life of the GMP Foundational Investments, Rhode Island Energy expects Rhode Island customers and society to realize total benefits of $3.9 billion Nominal and $2.5 billion NPV-$2023.

The Nominal and NPV values for each benefit category are shown in the table below:

Benefit Types	Benefits by Type	B/C Ratio	Benefits by Type	B/C Ratio
	Nominal ($M)		NPV ($M)	
Utility Savings	$ 2,928.8	5.5	$ 1,768.6	4.7
Direct Customer Savings	$ 527.7	6.5	$ 377.1	5.7
Societal Savings	$ 490.4	7.5	$ 379.1	6.8
Total Savings	$ 3,946.9		$ 2,524.7	
Total Costs	$ 529.0		$ 373.8	

The Company also grouped the benefits expected from GMP investments into benefit categories depending on the "program" that would produce the benefits. Below are the Nominal and NPV values for each 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 basis for each of these quantified benefits is described in Section 8.3 of the GMP.

Q. What non-quantified benefits did the Company consider in the BCA?

A. There are several non-quantified benefits the Company considered. Below is a list of benefits not quantified by the Company. Please note that this list is not exhaustive.

- **Reduced Losses –** 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. Please see Attachment K to the GMP for additional detail.
- **Local Economic Impacts:** not quantified in this BCA is the impact of the significant GMP investments on the Rhode Island economy. 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 the 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, enabled by AMF and other grid modernization investments, will allow 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 the costs they represent, a more fair and equitable allocation of electricity sector costs results.

- **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 grid operators to actively manage grid demand and grid supply, thereby maximizing asset utilization, allowing dispatch of a more efficient mix of generation and ancillary services (e.g., spinning reserve, frequency regulation), reducing transmission congestion to reduce generation and transmission costs, and, ultimately, reducing 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 need the NWA for reliability during a certain time period.
- **Improved Storm Recovery due to Granular Data and Distributed Automation:** Although 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 impacts to outages caused by major storm events. 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 the ability for the 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 and can provide additional reliability benefits, which have not been quantified to date.

Q. Please explain how the Company assessed the costs of the GMP.

A. Section 8.4 of the GMP describes how the Company calculated the costs for the BCA. In brief, costs were developed for a 20-year analysis period, both in nominal values and in NPV. The GMP investments are categorized as Operational Systems and Applications, Advanced Field Devices and Communications (Fiber). The costs were developed through research and working with subject matter experts from both Rhode Island Energy and PPL Electric. The costs for the bulk of the GMP were developed as part of the FY 2024 Electric ISR Plan. The FY 2024 Electric ISR Plan includes only the Install component for distribution investments; the GMP includes Install, Removal, Run the Business ("RTB") operational expenses, and RTB for telecommunications for distribution and transmission investments.

Q. What are the summary costs of the BCA for the GMP Foundational Investments?

A. Over the 20-year life of the GMP Foundational Investments, Rhode Island Energy expects the total costs will be \$529.0 million Nominal and \$373.8 million NPV (\$2023).

The NPV is approximately 70 percent of the Nominal costs because the bulk of the investment occurs in years 2023 – 2028.

Below are the Nominal and NPV values for each cost category discussed above:

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**

Q. What were the overall results of the BCA?

A. Over a 20-year evaluation period, Rhode Island Energy expects to invest $529 million Nominal and $373.8 million on a $2023 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.

Q. Which sensitivities did the Company consider in developing the BCA?

A. Rhode Island Energy evaluated two types of sensitivities: basic sensitivities and issue-specific sensitivities. The basic sensitivities involved varying costs and benefits by some percentage to reflect the uncertainty that particular levels of costs or benefits will be achieved. The issue-specific sensitivities include a 10-year sensitivity, which reviews costs and benefits for only the first 10 years of the 20-year study period, and a carbon cost sensitivity, which looks at the benefits and benefit/cost ratios if the carbon cost were set at the New England Marginal Abatement Cost rather than the Social Cost of Carbon.

Q. How did the Company apply the sensitivities to the benefit categories?

A. Rhode Island Energy varied all of the seven benefit categories. The benefits were all varied by +/-20 percent. The NPV benefit/cost ratios for the individual favorable sensitivities range from 6.8 to 7.1, and combining all of them results in a benefit/cost ratio of 8.1. 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 6.4 to 7.1, and combining all of them results in a benefit/cost ratio of 5.4. Even given all the benefits being lower than forecast, the benefit/cost ratio remains very strong.

Q. How did the Company apply the sensitivities to the cost categories?

A. The Company performed cost sensitivities that involved varying each of four categories of costs. Those categories are Communications and IT costs, DER Monitor/Manage costs, Advanced Field Device costs, and Run the Business costs. Rhode Island Energy varied the Communication and IT costs and the DER Monitor/Manage costs by +/-25 percent. The Company has extensive experience with purchasing and installing field devices and maintaining them; those two categories were varied by +/-10 percent. The benefit/cost ratios for the individual favorable sensitivities range from 6.8 to 7.4, and combining all of them results in a benefit/cost ratio of 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 combining all of them results in a benefit/cost ratio of 5.8. Even given all the costs being higher than forecast, the benefit/cost ratio remains very strong.

Q. Did the Company attempt to develop "best" and "worst" case scenarios?

A. Yes. Rhode Island Energy combined the unfavorable cost and benefit sensitivities to develop a "worst case" scenario. The Company combined the favorable cost and benefit sensitivities to develop a "best case" scenario. The "best case" scenario had a benefit/cost ratio of 9.8, while the "worst case" scenario had a benefit/cost ratio of 4.6. Even in the "worst case," the GMP program results remain very strong.

Q. What were the results of the issue-specific sensitivities?

A. Looking at the benefits and costs over only the first 10 years of the study period yielded results shown below.

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 involved the cost of carbon and the results are shown below.

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

Q. What is the Company's conclusion about the GMP given the BCA analysis?

A. The BCA performed by the company results in extremely positive results under the base case and the sensitivities performed. Not only are the grid modernization investments critically needed to maintain and enhance safety and reliability, they will provide significant benefits to the customers of Rhode Island Energy.

Q. In conclusion, why is it important to invest in grid modernization?

A. The increased penetration of DER, reinforced by the Climate Mandates, has created additional system complexity that Rhode Island Energy's electric distribution system simply cannot handle. Many factors that have been discussed in the GMP support the conclusion that the Foundational Investments, which will bring grid modernization capability to fruition in Rhode Island, are urgent and needed now to maintain and enhance safety and reliability. Furthermore, the quantitative BCA results in just over two 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 1.0. And, the BCA results remained positive for all cost, benefit and time sensitivities that were tested. Grid Modernization, via the Foundational Investments, is needed to satisfy unmet operational, customer and clean energy needs, is urgent, and is cost effective.

The Foundational Investments in this GMP: (i) provide a net benefit under any future scenario, (ii) provide confidence in moving forward on a path that is known to have uncertainties, (iii) align stakeholders to a course of action, (iv) address unmet operational, customer and clean energy needs that are evident now and will become more evident in the future, (v) provide opportunities to establish a basis where adjustments can be made over the long term to deliver the highest value, and (vi) provide an avenue to take concrete action.

Q. What will happen if Rhode Island does not invest in grid modernization?

A. The Distribution Study concludes that without Foundational Investments:

(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 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.

In addition, without grid modernization, Rhode Island customers will be impacted because:

(1) VVO cannot be effectively implemented;

(2) Customer outages and restoration time will continue to get worse;

(3) TVR/CPP cannot be properly implemented;

(4) Transmission and distribution infrastructure costs will increase significantly;

(5) DER curtailment will increase;

(6) Utility O&M costs will continue to increase; and

(7) Overall cost to consumers will rapidly increase because of not achieving the cost benefits of GMP.

XI. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.