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April 29, 2026

***Via Hand Delivery and Electronic Mail***  
Stephanie De La Rosa, Commission Clerk  
Rhode Island Public Utilities Commission  
89 Jefferson Boulevard  
Warwick, Rhode Island 02888

**RE: Docket No. 25-19-EL – The Narragansett Electric Company d/b/a Rhode Island Energy Proposed Green Button Connect, Home Area Network, and Grid Edge Computing**  
**Legal Memorandum – May 13, 2026 Evidentiary Hearing**

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the “Company”), enclosed please find the Company’s legal memorandum regarding the scope of the May 13, 2026 evidentiary hearing in the above-referenced docket.

An original and five (5) copies of each filing will be hand delivered in addition to the electronic version. Thank you for your attention to this matter. Please do not hesitate to contact me should you have any questions.

Very truly yours,

A handwritten signature in black ink that reads "Christine Dieter".

Christine E. Dieter

Enclosures

cc: Docket 25-19-EL Service list (via electronic mail)

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

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<b>THE NARRAGANSETT ELECTRIC</b>	)	
<b>COMPANY D/B/A RHODE ISLAND</b>	)	Docket No. 25-19-EL
<b>ENERGY'S PROPOSED GREEN BUTTON</b>	)	
<b>CONNECT, HOME AREA NETWORK,</b>	)	
<b>AND GRID EDGE COMPUTING PLANS</b>	)	

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**LEGAL MEMORANDUM OF THE NARRAGANSETT ELECTRIC COMPANY  
D/B/A RHODE ISLAND ENERGY REGARDING THE SCOPE OF THE  
MAY 13, 2026 EVIDENTIARY HEARING**

The Narragansett Electric Company d/b/a Rhode Island Energy (the “Company”) respectfully submits this legal memorandum regarding the scope of the May 13, 2026 evidentiary hearing scheduled by the Rhode Island Public Utilities Commission (the “Commission”) for May 13, 2026.<sup>1</sup> For the reasons set forth below, the Company respectfully submits that it reasonably relied on the Commission’s decisions in *In re Rhode Island Energy Advanced Metering Functionality Business Case and Cost Recovery Proposal*, Docket No. 22-49-EL, to advance the development of the Green Button Connect (“GBC”) functionality in connection with AMF deployment. The Company therefore requests that the Commission limit the scope of the May 13, 2026 evidentiary hearing to ensuring that the Company is held accountable for delivering the GBC functionalities promised in the AMF Business Case, as discussed below, or, in the alternative, that the Commission not disallow costs already incurred by the Company in developing GBC.

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<sup>1</sup> Pursuant to the Scheduling Order established by the Commission, the Company intends to file rebuttal testimony on May 8, 2026, outlining its factual positions in advance of the evidentiary hearing scheduled for May 13, 2026. This legal memorandum therefore focuses on the Company’s legal interpretation of the Commission’s Report and Order in *In re Rhode Island Energy Advanced Metering Functionality Business Case and Cost Recovery Proposal*, Docket No. 22-49-EL (May 20, 2025).

**I. BACKGROUND**

**A. The Commission’s Review and Authorization of the Company’s AMF Business Plan, Docket No. 22-49-EL**

This docket arises from, and serves to implement a portion of, the Company’s AMF Business Case. The Company filed its AMF Business Case with the Commission on November 18, 2022. Following an approximately ten-month review, on September 27, 2023, the Commission voted at an open meeting to authorize the Company to deploy an AMF-metering system for the electric distribution system subject to several conditions. A copy of the Open Meeting Motions and Votes is attached as Exhibit 1 (the “Open Meeting Votes”). The Commission issued a written Report and Order on May 20, 2025. *See* Report and Order, No. 25353, *In re Rhode Island Energy Advanced Metering Functionality Business Case and Cost Recovery Proposal*, Dkt. No. 22-49-EL (Pub. Utils. Comm’n May 20, 2025) (hereinafter the “AMF Order”). A copy of the AMF Order is attached as Exhibit 2.

At the September 27, 2023 Open Meeting, the Commission voted unanimously to “authorize the Company to seek recovery of its capital investments” through the Infrastructure, Safety, and Reliability (“ISR”) process “with an overall multi-year CapEx cap” and imposed six conditions on the Company should it decide to proceed with the AMF investment. Open Meeting Votes ¶ 3. As is relevant to this docket, the Commission stated that, “The scope of the authorized deployment includes the investments and functionalities, as set forth in Figure 6.2 and Figure 6.3 but shall not include CP: Solar Marketplace, CP: Carbon Footprint Calculator, and CP: C&I and Multi-Family Portfolio View.” *Id.* ¶ 3(b); *see also* AMF Order, Ordering Paragraph 6(b) (same). A copy of the complete Figures 6.2 and 6.3 from the AMF Business Case is included as Exhibit 3. Figure 6.3 of the AMF Business Case included the following functionalities:

**Figure 6.3: AMF Functionalities During Meter Deployment**

AMF Functionality	Working Definition
CP: Green Button Connect	Enables customers to transfer energy usage data at a standard latency to authorized third parties.
CEMP - Bill Alerts	Alerts for variety of customer needs. Examples include projected high-bill (consumption and/or costs), prediction of peak demand or usage, and customizable threshold alert at various points during a billing period.
CP: Near Real-Time Customer Data Access	Availability of near real-time raw usage data through the customer portal. This allows 15-minute electrical raw usage data, available within 30-45 minutes, updated with bill quality data within 24 hours.
CP: In-Home Device Support	Enable communications between a customer owned home Device and the AMF meter.
ADMS: Voltage Conservation (Volt-Var Optimization)	Providing interval meter voltage and reactive power data to the ADMS to support conservation voltage reduction (CVR) and Volt-Var Optimization (VVO).
ADMS: Voltage Automated Notification (Sag/Swell)	Configurable real-time alert for momentary under or over voltage on a meter, integrated to ADMS for immediate action.
ADMS: On Demand Voltage Measurement (to ADMS)	ADMS function to ping networked electric devices and meters for voltage measurements.
ADMS-DER: Monitor & Management	Enabling the ability to monitor & manage distributed energy resource (DER) inverter based infrastructure (eg. battery banks, solar PV, net-meters).

**Figure 6.3: AMF Functionalities Enabled During Meter Deployment (continued)**

AMF Functionality	Working Definition
Network Model Analytics	MDMS functionality to support analysis of the network, identifying outlier issues for investigation (e.g. misassociated meters).
Theft Detection Analytics	MDMS functionality to identify outlier patterns that indicate potential energy theft.
CP: Solar Marketplace	Customer portal functionality that creates an integrated marketplace for customer research of solar PV adoption.
CP: Carbon Footprint Calculator	Customer portal functionality that creates an ability for customers to calculate carbon footprint based on usage data and actions to better manage usage.
CP: C&I and Multi-Family Portfolio View	Customer portal functionality that enables a portfolio view of C&I facilities as well as properties for multifamily unit owners and managers.

The Commission further required the Company to certify that, if it opted to move forward with the AMF investment, then the Company would provide **all** the functionalities identified by the Commission:

When the Company submits its compliance filing, it needs to certify that it is committing to making the investments, **achieving the functionalities identified above**, and bearing the financial risk of exceeding the approved Capex Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed.

Open Meeting Votes ¶ 5 (emphasis added); *see also* AMF Order, Ordering Paragraph 8 (same).

As part of its authorization to allow the Company to move forward with AMF implementation, the Commission imposed numerous “Accountability Requirements” to ensure that the Company’s investment delivered the promised value to customers. *See* Open Meeting Votes p. 3. The Commission required that “the effect of the CapEx cap is that the Company will be required to keep spending, even if above the cap, until it achieves the functionalities as set forth in the prior motions today.” *Id.* ¶ 11; *see also* AMF Order, Ordering Paragraph 14 (same). As described in the written AMF Order in Section VIII titled “Accountability Measures,” “the CapEx Cap was only one accountability measure designed to protect ratepayers.” AMF Order p. 21. The Commission imposed additional accountability metrics in three areas: “Updates/Additions to Service Quality Mechanisms; Planning and Transparency for Customer-Facing Technologies; and Timely Functional Use of AMF Capabilities.” *Id.* The second accountability metric related to GBC:

The second area focuses on planning and transparency related to customer-facing technologies, specifically addressing functionalities provided by Green Button Connect, Home Area Networks, and Grid Edge Computing, which are intended to enhance customer access to energy data and facilitate integration with third-party technologies. The Company’s proposals, consistent with Ordering paragraph 16, shall be filed within two months of the start of meter installation and will be considered in a contested case. It will be important to understand the technical issues around data governance and customer access to data. Some parties

advocated for a formal stakeholder proceeding to define these items but the Commission, while encouraging stakeholder outreach, declines to order the creation of a formalized group, instead preferring an initial filing and responsive filings to ensure full transparency that can get lost in a settlement.

AMF Order p. 22. Paragraph 16 of the AMF Order identified specific elements that the Company's GBC, HAN, and grid-edge computing plans must address. *Id.* at 27; *see also* Open Meeting Votes ¶ 13 (identifying the filing of the plans as one of four categories of "Accountability Requirements").

Following the Open Meeting Votes, the Company filed written certification of its intent to proceed with the AMF investment. A copy of the certification is attached as Exhibit 4.

Specifically, the Company certified to the following:

The Company commits to making the investments, **achieving the functionalities identified above**, and bearing the financial risk of exceeding the approved Capex Cap (as that term is defined in the [Open Meeting Votes]) for those investments identified in the scope of the implementation plan as set forth in the Company's revised response to Record Request 9, which is being submitted contemporaneously with this Certification. The Company further confirms that it will move forward with implementing AMF **under the terms of the Commission's authorization and subject to the conditions** set forth by the Commission in the [Open Meeting Votes].

Certification 1 (emphasis added). In reliance on the Open Meeting Votes and this written certification, the Company to date has spent approximately \$170,000 to implement the GBC functionality.<sup>2</sup>

**B. The Company's GBC Compliance Filing**

Consistent with the Open Meeting Votes, the Company made a compliance filing with the Commission on May 12, 2025, to provide the GBC Plan, along with the HAN and grid-edge computing plans. The Commission subsequently opened the above-referenced docket to review the plans.

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<sup>2</sup> The Company intends to offer witness testimony to support this amount in its rebuttal testimony.

Following the filing of motions to intervene by Mission:data Coalition (“MDC”) and others,<sup>3</sup> the Commission held an open meeting on August 21, 2025, to review the motions and the Company’s response. The Commission allowed the motions to intervene, including that of MDC, but explained the narrow and specific scope of this docket and limited all parties to that scope. Specifically, the Commission limited the scope of the docket to Ordering Paragraph 16 of the AMF Order “and any items directly related to data governance or customer data.”

The Commission held a technical session on October 29, 2025. MDC subsequently submitted pre-filed direct testimony on December 5, 2025, in accordance with the Commission’s scheduling order. The Company moved to strike MDC’s testimony, in part, on December 12, 2025, on the ground that the pre-filed testimony exceeded the scope of this docket. The Commission held oral argument on the motion on December 17, 2025.

The Commission held an open meeting on March 4, 2026, to rule on the Company’s motion to strike. During that Open Meeting, the Commission stated that the scope of the current docket would include whether to authorize the Company to proceed with GBC. No party had previously argued to the Commission that the scope of this docket included the question of whether or not the Company should be authorized to proceed with GBC. The Commission’s open meeting decisions identified the scope of the upcoming May 13, 2026 evidentiary hearing as follows:

- a. The purpose of the hearing will be limited to the following questions:
  - i. Whether the Company should be authorized or required to move forward with the Green Button Connect plan as described in the filing, subject to further review after the Company certifies that the plan is ready for implementation and the Company performs a live demonstration (if such demonstration is requested by the Commission), and

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<sup>3</sup> The Conservation Law Foundation, George Wiley Center, and Good Energy, L.P. also moved to intervene. The Rhode Island Office of Energy Resources provided notice that it intended to intervene as of right. *See* R.I. Gen. Laws § 39-1-27.9.

- ii. Whether the Commission should decline to authorize or require the Company to move forward with the plan as described in the filing, and, as a consequence, whether the Commission should order a reduction in the AMF investment cost cap by the projected cost of Green Button Connect in the amount of \$664,000, as shown in the Company's Attachment PUC 1-4-2-Supplemental in Docket No. 25-54-EL.
- b. The Commission will not consider any expansions to the Green Button Connect plan which would conflict with the Company's management discretion to offer Green Button Connect functionality that the Company is willing to develop and implement.

Mar. 4, 2026 Open Meeting Decisions, attached as Exhibit 5.

Both the Company and MDC requested an opportunity to file supplemental testimony and briefing following the open meeting. The Company now submits this legal memorandum pursuant to the schedule established by the Commission.

## **II. THE AMF ORDER REQUIRED THE COMPANY TO IMPLEMENT GBC.**

### **A. The AMF Order Included GBC within the Required Functionalities.**

The Company respectfully submits that the AMF Order required the Company to move forward with implementing a GBC plan as a condition of its decision to deploy the AMF meters. Both the Open Meeting Votes and the AMF Order stated that the scope of the deployment must include the investments and functionalities "as set forth in Figure 6.2 and Figure 6.3." Open Meeting Votes ¶ 3(b); AMF Order, Ordering Paragraph 6(b). GBC is included in Figure 6.3, which outlined the AMF functionalities that would be developed "during meter deployment." *See* Exh. 3. The Open Meeting Votes and AMF Order required the Company to certify its commitment to "achieving the functionalities identified above," which included GBC. The Company made the required certification on December 22, 2023, Exh. 4, and proceeded soon thereafter with AMF implementation.

Notably, the Commission declined to authorize the Company to advance three functionalities listed in Figure 6.3. The Open Meeting Votes and AMF Order excluded the CP: Solar Marketplace, CP: Carbon Footprint Calculator, and CP: C&I and Multi-Family Portfolio View functionalities from the scope of authorized deployment. Open Meeting Votes ¶ 3(b); AMF Order, Ordering Paragraph 6(b). This explicit exclusion of some functionalities from the scope but not others – such as GBC – further demonstrates that GBC fell within the scope of “the functionalities identified above” that the Commission expected the Company to achieve if it opted to move forward with the AMF investment. Open Meeting Votes ¶ 5; AMF Order, Ordering Paragraph 8.

**B. The AMF Order Established Review of the GBC Plan as an Accountability Measure.**

Separate from the conditions under which the Commission authorized the Company to proceed with the AMF investment, the Commission also established multiple accountability measures to ensure that customers receive the anticipated benefits of the AMF investment. In both the Open Meeting Votes and AMF Order, these accountability measures were identified separately from the authorization to proceed with the investment, under headings specifically labeled “Accountability Requirements” (Open Meeting Votes) and “Accountability Measures” (AMF Order). Open Meeting Votes p. 3; AMF Order p. 21.

The sections relating to accountability measures did not establish processes that indicated that the Company faced potential disallowance of costs otherwise recoverable under the cost cap. Rather, the accountability metrics drove toward requiring the Company “to keep spending, even if above the cap, **until it achieves the functionalities** as set forth in prior motions today.” Open Meeting Votes ¶ 11 (emphasis added); AMF Order, Ordering Paragraph 14 (emphasis added). There was no indication that the scope of the contested proceeding regarding the GBC, HAN,

and Grid-Edge Computing implementation plans included revisiting whether the Company had to deliver these functionalities or face potential cost cap reductions. Rather, as noted in the PUC’s August 21, 2025 Open Meeting decision on the motions to intervene, the scope was limited to Ordering Paragraph 16 from the AMF Order.

The Open Meeting Votes identify the requirement to file a GBC plan as an accountability requirement. *See* Open Meeting Votes p. 3-4. Similarly, the AMF Order discusses GBC in the section on accountability measures. *See* AMF Order p. 21-22. This area of accountability measures “focuses on planning and transparency.” *Id.* p. 22. The AMF Order indicates that GBC should “enhance customer access to energy data and facilitate integration with third-party technologies.” *Id.* It further states that, “It will be important to understand the technical issues around data governance and customer access to data.” *Id.* The AMF Order therefore outlines the functionalities that GBC should achieve and identifies certain elements relevant to holding the Company accountable for achieving the functionalities. It did not contemplate revisiting whether to proceed with GBC or implement a potential reduction of the cost cap.

**III. THE EVIDENTIARY HEARING SHOULD FOCUS ON ENSURING THAT THE COMPANY DELIVERS THE GBC BENEFITS PROMISED IN THE AMF BUSINESS CASE.**

For the reasons outlined above, the Company respectfully submits that the purpose of the current docket is not to authorize or decline to authorize the Company to proceed with GBC; the Open Meeting Votes and AMF Order directed the Company to provide the GBC functionality as a condition of proceeding with the AMF investment. Rather, this docket should focus on ensuring that the Company delivers the GBC benefits outlined in the AMF Business Case and reiterated in the GBC plan. These include enhancing customers’ access to their energy data and

facilitating data transfer to third parties, all while providing appropriate safeguards to protect the privacy of customer data.

As will be explained in the Company's rebuttal testimony, the Company has worked for more than a year to develop the GBC functionality and has incurred associated costs as outlined in the AMF Business Case. The Company did so in a prudent manner and in reasonable reliance on the Open Meeting Votes and AMF Order. The Company respectfully submits that the disallowance of costs already incurred by the Company to implement GBC would be inappropriate under the circumstances.

#### **IV. CONCLUSION**

For the reasons set forth in this legal memorandum, the Company respectfully submits that it reasonably proceeded to develop the GBC functionality in reliance on the Open Meeting Votes and AMF Order. The Company requests that the Commission limit the scope of the May 13, 2026 evidentiary hearing to ensuring that the Company is held accountable for delivering the promised GBC functionalities or, in the alternative, that the Commission not disallow costs already incurred by the Company in developing GBC.

Respectfully submitted,

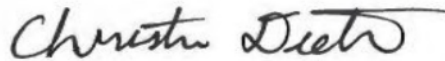
**THE NARRAGANSETT ELECTRIC  
COMPANY D/B/A RHODE ISLAND  
ENERGY**

By its attorneys,



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Dated April 29, 2026

**CERTIFICATE OF SERVICE**

I hereby certify that on April 29, 2026, I sent a copy of the foregoing to the service list by electronic mail.

/s/ Christine E. Dieter

# **EXHIBIT 1**

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

**IN RE: RHODE ISLAND ENERGY ADVANCED :  
METERING FUNCTIONALITY BUSINESS CASE : DOCKET NO. 22-49-EL  
AND COST RECOVERY PROPOSAL :**

**OPEN MEETING MOTIONS AND VOTES**

**Finding of Need and Authorization for Deployment**

- (1) Move to find that there is a need for the Company to transition its electric distribution operations from the existing AMR-based metering system to a system that utilizes advanced metering functionality (AMF). RG, AA Vote 3-0

**Capital Cost Recovery through the ISR**

- (2) Move to reject the Company’s proposal for a new AMF recovery factor. RG, AA Vote 3-0
- (3) Move to authorize the Company to seek recovery of its capital investments in the categories identified in Record Request 9 through the infrastructure, safety, and reliability (ISR) process as discretionary investments through the creation of a separate category with an overall multi-year CapEx cap, with the following conditions:
- (a) The Company is not required to prove a need to deploy AMF for its electric distribution operations in place of the existing AMR-based metering system;
  - (b) The scope of the authorized deployment includes the investments and functionalities, as set forth in Figure 6.2 and Figure 6.3 but shall not include CP:Solar Marketplace, CP:Carbon Footprint Calculator, and CP: C&I and Multi-Family Portfolio View.
  - (c) The scope shall also include advancement of load disaggregation & Waveform Analytics and Grid Edge Computing that will be enabled by allowing customers to use Sense by connecting their home area network to the meter as discussed in RR-11 and shall not include acceleration of TVR.
  - (d) Capital spending within the scope of Record Request 9 (Project Implementation) that was commenced prior to the ISR Fiscal Year 2025 filing shall be eligible for ISR recovery notwithstanding the fact that the spending was not part of the pre-approved investments within the rules of a prior ISR filing;
  - (e) Recovery of the capital costs incurred for the authorized project implementation period shall be capped in the aggregate at a budget of \$153,217,548 and the Company is directed to file a revised RR-9 and revised Attachment H excel

spreadsheet to reflect \$0.00 for the items removed and to show the O&M related to acceleration of Sense.

- (f) Regarding the Special Sector Deferrals identified in the Amended Settlement Agreement and listed in Attachment PUC 7-13, lines 3 and 4, the ongoing annual net cumulative accrual shall only be used to offset the annual AMF revenue requirement that is eligible for ISR cost recovery each year.

RG, AA Vote 3-0

- (4) Move that the Meter Data Management System (MDMS) costs shall not be eligible for rate base recovery; provided, however, 44% of the capital costs associated with the work performed by Landis+Gyr which the Company allocated to AMF shall be amortized over the depreciation period applicable to the asset type and recovered through the ISR without a return. RG, AA Vote 3-0
- (5) When the Company submits its compliance filing, it needs to certify that it is committing to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved Capex Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed. RG, JR Vote 3-0
- (6) Move to direct the Company to file an ISR Addendum to encompass the findings herein for further review by the Commission. The addendum shall include a proposal to recover the revenue requirement associated with the eligible AMF CapEx spending to be appropriately allocated to each rate class and recovered through a fixed charge embedded in the applicable customer charge for each rate class for further review by the Commission. RG, AA Vote 3-0

**Treatment of O&M Expenses Prior to Next Rate Case**

- (7) Move that any operation and maintenance (O&M) expenses (i) relating to the AMF project implementation period or (ii) relating to AMF “run-the-business” costs, which expenses are incurred during the period prior to new base distribution rates going into effect from the next base distribution rate case may not be deferred or recovered in any new rates. RG, AA, Vote 3-0
- (8) Move that effective on the date of this decision through the effective date of the Company’s next base distribution rates, the Company may net O&M expenses that relate to the AMF scope as defined above against the accumulating regulatory liability relating to certain residual revenue requirement items identified in Docket 4770 and enumerated in PUC 7-13, RR-7, and/or RR-13. To the extent that such O&M expenses during that period are less than the total accumulated regulatory liability as of the date that new base distribution rates go into effect, the regulatory liability shall remain in effect and the balance shall be applied for the benefit of ratepayers in a manner determined by the Commission. RG, JR Vote 3-0

- (9) Move to direct the Company to file a schedule that updates Attachment PUC 7-13 with actuals through Rate Year Ending August 31, 2023, includes the AMF-related portion of all other grid mod costs identified on line 25, page 7 of 9, Compliance Attachment 1 in the Docket No. 4770 Compliance Filing (Amended Settlement Agreement Book 1) that was identified in SAB/BLJ-1, and provides a forecast through the anticipated effective date of the next base distribution rate case. In addition, the Company shall provide the cumulative balances as of August 31, 2023 in a separate section. RG, JR Vote 3-0
- (10) Move to direct the Company to update the revised schedule that was just voted on with each annual ISR filing and reconciliation filing and also include a schedule which shows the O&M expenses that have been netted against the rate level credit balance. RG, JR Vote 3-0

### **Accountability Requirements**

- (11) Move that the effect of the CapEx cap is that the Company will be required to keep spending, even if above the cap, until it achieves the functionalities as set forth in prior motions today. AA, JR Vote 3-0
- (12) Move to adopt the following requirements the Company must comply with under the authorization to advance its AMF investment plan:
- ADMS Integration: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the meter data is integrated into the ADMS. The company should report on the number of meters installed, time to install the meters, integration with ADMS, and any outliers. Prior to commencing meter installation the company needs to provide the PUC and DPUC definitions of the geographic deployment areas.
  - Voltage Notification: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the company has configured real time alerts for over/under voltage and is using the ADMS ping to investigate voltage issue.
  - Outage Notification: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for outage notification.
  - Remote Connect/Disconnect: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for remote connect, disconnect, service activation, and account transfers.
  - Theft Detection: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for theft detection.
  - Customer Portal: Company will maintain a customer portal. At a minimum, there should be no discontinuity of customers' ability to access account information and pay bills online.

Load Disaggregation: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that customers are able to access disaggregated load data. Within 12 months of the conclusion of the deployment period, the company will report on customer access and utilization of disaggregated load data.

AA, JR Vote 3-0

- (13) Move that within two months of the start of meter installation, the Company must file plans that address Green Button Connect, Home Area Network, and Grid Edge Computing, as described below. The company may consult with any stakeholder deemed necessary, but the plan must be filed by the company and will be reviewed by the Commission in a contested proceeding.

Green Button Connect: Within two months of the start of meter installation, the company must file a Green Button Connect plan that addresses the following:

- a. For every customer specific item on the bill, whether that same information should be provided through GBC;
- b. At a minimum, the company should plan to provide the same data fields and historical information as offered or planned to be offered to its customers in Pennsylvania and Kentucky.
- c. For each of the items in (a), whether the underlying customer-specific data (e.g. interval meter reads, voltage) should be provided through GBC;
- d. To the extent historical data is provided for (a) and (b), provide the extent of that data set. Specifically address whether it is appropriate to provide 36 months of electric consumption.
- e. Whether (a), (b), and (c) should be provided for gas.
- f. Whether any additional customer specific data beyond (a) and (b) should be provided through GBC (e.g. disaggregated load data).
- g. Timeline for GBC certification and version of certification.

Home Area Network: Within two months of the start of meter installation, the company must file a Home Area Network plan that addresses the following:

- h. Version of bring-your-own-device that will be offered to customers, and requirements, if any, on those devices;
- i. Access to usage and disaggregation insights;
- j. Whether any charges apply to customers or device-makers;
- k. Technical standards for local devices;
- l. Terms and conditions on direct upload of usage data and disaggregation insights.

Grid Edge Computing: Within two months of the start of meter installation, the company must file a Grid Edge Computing plan that presents a framework or terms and conditions for each issue identified in Mission:data Coalition's Post-Hearing Statement section 3, parts (a) through (f).

AA, JR Vote 3-0

- (14) Move to direct Rhode Island Energy to engage with the DPUC to negotiate the details and implementation of the following service quality mechanisms and file an updated Service Quality Plan for Commission review and approval in Docket 3628 within 3 months. Other parties will be able to intervene in Docket 3628.
1. Meter reading & billing:
    - a. Monthly percent of meters read is an existing reporting requirement in the service quality plan in Docket 3628.
    - b. The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period.
    - c. The service quality mechanism should establish a threshold that represents appropriate performance (e.g. the average of the past three years).
    - d. The maximum penalty will be imposed for performance 2.5 standard deviations below the threshold.
    - e. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum penalty was determined.
    - f. The design may or may not be linear, and it may include a dead band.
    - g. Following the meter installation period, the Company and Division may propose an update to this service quality mechanism in Docket 3628.
  2. Faster outage notification:
    - a. The company will be subject to a one-time faster outage notification service quality mechanism 12 months after full project implementation.
    - b. The service quality mechanism should establish a baseline for outage notification.
    - c. The maximum penalty will be imposed if evidence shows that the company is notified of outages 0 minutes faster than the baseline.
    - d. No penalty will be imposed if evidence shows that the company is notified of outages 22 minutes faster than the baseline.
    - e. The metric may be an annual average over all customers or explain why a different metric was chosen.
    - f. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
    - g. The mechanism may or may not be linear. Intervals, bins, and dead-bands may be considered.
    - h. The mechanism may (but is not required to) include a shared savings mechanism for evidence that that the company is notified of outages more than 23 minutes faster than the baseline.
  3. Network speed:
    - a. The company will be subject to a one-time or continuous network speed service quality mechanism 12 months after full project implementation.
    - b. The service quality mechanism should establish a measurement of network speed. The measurement should capture the speed of information from the meter to the MDMS and back to the customer portal or explain why a different measurement

was chosen. The service quality mechanism should establish the time period and scope of the measurement.

- c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
  - d. The company and parties should propose the maximum penalty and threshold. Intervals, bins, and dead bands may be considered.
4. Trouble, Non-Outage
- a. Trouble, non-outage calls are an existing reporting requirement in the service quality plan in Docket 3628.
  - b. Within twelve months after meter installation starts, the company will be subject to a service quality mechanism for trouble, non-outage calls.
  - c. The service quality adjustment should impose scaled penalties for increased trouble, non-outage calls, compared to a baseline. The metric, baseline, minimum, and maximum should be defined and justified.
  - d. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
5. Customer satisfaction
- a. Customer satisfaction (customer contact survey) is an existing service quality mechanism in the service quality plan in Docket 3628.
  - b. Within six months after meter installation starts, the company will be subject to an updated customer contact standard that reflects the company's expectations of higher customer satisfaction. Updates may include, but not be limited to, increasing the minimum percent satisfied threshold, increasing the value of the penalty, and narrowing the dead band.
  - c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.

AA, JR Vote 3-0

### **Conclusory Motions**

- (15) The Commission authorizes the Company to deploy an AMF-based metering system for the electric distribution business subject to the conditions already voted on. RG, AA Vote 3-0
- (16) The Company is not required to commence the authorized project implementation. The decision to move forward under the terms of the Commission's authorization rests within the management discretion of the Company; provided, however, if such project implementation is commenced, the conditions set forth by the Commission in the decisions today shall apply. RG, AA Vote 3-0.

# **EXHIBIT 2**

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

**IN RE: RHODE ISLAND ENERGY ADVANCED           :**  
**METERING FUNCTIONALITY BUSINESS CASE       :**       **DOCKET NO. 22-49-EL**  
**AND COST RECOVERY PROPOSAL                 :**

**REPORT AND ORDER**

**I.       Overview**

On November 18, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy (RI Energy or Company) filed with the Public Utilities Commission (Commission) an Advanced Metering Functionality (AMF) Business Case to support its proposed investment plan to replace the current automated metering reading (AMR) system and an accompanying new cost recovery mechanism.<sup>1</sup> RI Energy explained that:

AMF refers to the functionality provided by advanced meters, also referred to as smart meters, while AMR refers to the presently used metering systems solution in Rhode Island to collect billing information with a “drive-by” technology. AMF is a broader concept than Advanced Metering Infrastructure (AMI); AMI commonly refers only to the smart meters themselves. AMF refers to the functionality that comes from the broader deployment of hardware and software solutions needed to utilize the smart meter data in a timely and efficient manner<sup>2</sup>

In other words, the investment plan includes more than just a simple meter replacement program. Instead, the proposed up-front cost associated with the new meters, communications network, and back-office systems will provide the Company with additional visibility into the distribution system to allow the Company more active management of the system and enable new rate structures.<sup>3</sup> Most of the costs would be incurred over a four-year period, including a three and

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<sup>1</sup> All filings in this matter can be accessed on the Commission’s website at: <https://ripuc.ri.gov/Docket-22-49-EL> or reviewed at the Commission’s offices

<sup>2</sup> RI Energy Filing, Book 2, at Bates page 1, n.2.

<sup>3</sup> RI Energy Filing, Book 2, at Bates pages 2-3. Section 4 of Book 2 of the Company’s Business Case contains the Company’s description of how AMF is an enabling platform. Bates page 43-56.

a half year implementation plan.<sup>4</sup> The original projected cost of capital (CapEx) and operation and maintenance (O&M) over the 20-year life of the investment was estimated at \$289.1 million, with \$167.93 million incurred in the first four years.<sup>5</sup>

As part of its filing, RI Energy initially proposed a new semi-annual recovery factor allowing it to recover both CapEx and OpEx costs as incurred on a six-month basis.<sup>6</sup> The Company's position was that once the Commission approved the AMF Business Plan, the Company was entitled to full recovery of costs of the investments associated with the AMF Business Plan. As described by the Company's testimony, the AMF Factor would recover the actual incremental costs of capital investments placed in service and the actual incremental O&M costs incurred.<sup>7</sup> The Company further explained that the actual O&M expenses included for cost recovery in the Company's proposal would be only the O&M costs incurred specifically for the AMF program. As base distribution rates do not currently include O&M costs for the AMF program, all O&M costs incurred for the AMF program proposed in this filing would be included for cost recovery.<sup>8</sup> There would be no hard cap on the amount of recoverable expenses, but the Company proposed a credit to customers of 80% of the assumed O&M savings that would result from the investment proposal.<sup>9</sup>

The Commission conducted a comprehensive review over a ten-month period, including interventions by the Rhode Island Attorney General (RIAG), the Office of Energy Resources (OER), Mission:data, the NRG Companies, the Conservation Law Foundation (CLF) and the

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<sup>4</sup> RI Energy Filing, Book 2, at Bates page 131.

<sup>5</sup> RI Energy Filing, Book 2, at Bates 161 and RI Energy's Response to RR-9.

<sup>6</sup> RI Energy Filing, Book 3, Bates pages 116-19.

<sup>7</sup> RI Energy Filing, Book 3, Bates page 6.

<sup>8</sup> RI Energy Response to PUC 1-3.

<sup>9</sup> RI Energy Filing, Book 3, Bates page RI Energy Response to PUC 1-4.

George Wiley Center.<sup>10</sup> There was an exchange of volumes of discovery, rounds of prefiled testimony, technical record sessions, public comment and multiple days of evidentiary hearings, and briefs. No party to the docket opposed the transition from AMR to AMI and the associated investments in functionality. On September 27, 2023, the Commission voted unanimously to authorize the Company to deploy an AMF-based metering system for the electric distribution business subject to several conditions, including a cap on CapEx cost recovery. The Commission specifically rejected the Company's AMF cost recovery proposal, instead approving an alternative cost recovery mechanism.<sup>11</sup>

## **II. Public Comment Concerns<sup>12</sup>**

### **A. Health and Safety**

The Commission received comments from the public expressing concern over potential health concerns and physical safety associated with the advanced meters. At the outset, the Commission notes that Rhode Island is in the minority of states that have not yet switched over to AMI.<sup>13</sup> The number of meters capable of two-way communication surpassed those only capable

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<sup>10</sup> The Division of Public Utilities and Carriers (Division) also participated in its role as an indispensable party before the PUC to represent the full body of ratepayers. As the Rhode Island Supreme Court has explained, “[i]t is the function of the division to serve the commission in bringing to it all relevant evidence, facts, and arguments that will lead the commission in its quasi-judicial capacity to reach a just result.” *Providence Gas Co. v. Burke*, 419 A.2d 263 (R.I. 1980). The RIAG, OER, Acadia Center, and GWC were admitted without condition. The NRG Companies and Mission:data were admitted subject to certain conditions as noted in the ordering paragraphs to this order. (PUC Minutes January 25, 2023; <https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-05/Minutes%20January%2025%202023.pdf>). Of the intervenors, only Mission:data presented a witness and filed testimony. On February 23, 2024, Acadia Center voluntarily withdrew from the case.

<sup>11</sup> During this proceeding, the Commission issued several orders on procedural matters. [Procedural Order 24586 Regarding Request for Confidentiality](#) (2/6/23); [Procedural Order 24591 Regarding Request for Confidentiality PUC 1-17](#) (2/21/23); [Procedural Order 24620 Regarding Objections to Certain Data Requests](#) (3/3/23); [Procedural Order 24653 Regarding Request for Confidentiality Relating to Vendor Name](#) (5/1/23).

<sup>12</sup> Two organizations provided comment in favor of the AMF proposal. All other comments, the majority of which were from out of state, opposed the proposal based on health and safety concerns.

<sup>13</sup> In 2022, U.S. electric utilities had about 119 million advanced (smart) metering infrastructure (AMI) installations, equal to about 72% of total electric meters installations. Residential customers accounted for about 88% of total AMI installations, and about 73% of total residential electric meters were AMI meters. Energy Information Administration Frequently Asked Questions; <https://www.eia.gov/tools/faqs/faq.php?id=108&t=3#:~:text=In%202022%2C%20U.S.%20electric%20utilities,electric%20meters%20were%20AMI%20meters>. (Site last visited May 15, 2025).

of one-way communication in 2013.<sup>14</sup> The Company addressed health concerns in Section 10 of its Business Case, noting that in other states, the concerns have been associated with radio frequency (RF) exposure. RI Energy provided links to various studies and summarized the results, primarily showing that the risk of exposure is at or below typical exposure from day to day living. In addition, RI Energy explained that the RF levels of the proposed meters are lower than the Federal Communication Commission's minimum guidelines.<sup>15</sup>

With respect to concerns raised about the accuracy, surge, and fire risks from the meters, the Commission requested the Company address those specific concerns. One of the concerns raised by members of the public was fire risk caused by lithium ion batteries in the meters. Company witness Walnock stated that there is no battery in an electric meter.<sup>16</sup> During the evidentiary hearing, he also described the process by which RI Energy reviews the safety and reliability of equipment it is purchasing. He explained that the safety requirements begin with the issuance of the Request for Proposals which requires the meters to meet certain national standards, such as those from the American National Standards Institute (ANSI) and a listing from the Underwriters Laboratory (UL). The safety requirements are included in the contract between the utility and the vendor. RI Energy will perform first level of testing on sample meters through their

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<sup>14</sup> Energy Information Administration, Electric Monthly Update, February 2015;

<https://www.eia.gov/electricity/monthly/update/archive/april2015/> (Site last visited May 15, 2025).

<sup>15</sup> RI Energy Filing, Book 2, Bates pages 124-28; The Company also explained that in 2015, the Maine Coalition to Stop Smart Meters challenged the Maine Public Utilities Commission's finding that smart meters do not pose a health risk. The case went to the Maine Supreme Judicial Court in 2016, which confirmed the Maine Public Utilities Commission's finding, ruling that smart meters installed by Central Maine Power Co. pose "no credible threat to the health and safety" of the utility's 615,000 customers who have them installed. The court cited the Maine Center for Disease Control and Prevention's findings in 2010, which concluded there was no indication of "any consistent or convincing evidence to support a concern for health effects related to the use of RF in the range of frequencies and power used by smart meters." (See e.g., Investigation by the Dep't of Pub. Util. on its own Motion into Modernization of the Elec. Grid, Docket D.P.U. 12-76-B at 37, <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9235208> (June 12, 2014)).

<sup>16</sup> Technical Session Tr. at 102 (June 13, 2023); capacitors have just enough power to send the "last gasp" signal to the Company when there is an electric outage; (Hrg. Tr. at 42 (Jul. 20, 2023)). The product specification do not include any reference to battery power. (See RI Energy Response to Mission:data 2-2).

meter engineers to ensure that they work appropriately. The next step, the evolution of that, then is that Landis+Gyr will take those meters to production.<sup>17</sup>

Once they have them produced, they will perform a test that's related to ANSI standards within their manufacturing facility and then Rhode Island Energy will perform "sample meter testing" by choosing meters from the lot at random. The meters will be tested based on the ANSI standards. These tests are designed to make sure things are operating as they should operate with accuracy. They also test for potential surges and voltage issues.<sup>18</sup>

Mr. Walnock noted that National Grid, in its filing before the NYPSC, was required to perform independent testing of the Landis + Gyr Revelo E360 meter – the meter proposed in Rhode Island – based on the ANSI C12 suite, which addresses factors such as heat, accuracy, and surge resistance. Landis+Gyr had an independent third party perform tests to certify those meters in about 2022. In October 2022, the NYPSC approved certification of the Revelo E360 residential meter.<sup>19</sup> In this case, the Commission finds that it is reasonable to rely on such certification from another utility regulator in lieu of requiring a similar study to be done less than one year later. This does not relieve RI Energy from its obligation to conduct appropriate due diligence on any equipment it is purchasing and using to provide safe and reliable service to its customers.

## **B. Opt-Out**

Customers who are concerned with the new meters will continue to have the option to opt out of their installation. Currently, there are a minimal number of customers of Rhode Island Energy who have chosen to opt out of the current AMR meters in favor of analog meters that are read monthly by a person on-premise. There is a monthly cost to cover the cost of the manual

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<sup>17</sup> Hr'g. Tr. at 137-39 (Jul. 20, 2023).

<sup>18</sup> Hr'g. Tr. at 139 (July 20, 2023).

<sup>19</sup> Hr'g. Tr. at 139-41 (July 20, 2023).

meter read.<sup>20</sup> At the hearing, Mr. Walnock testified that he expected customers who opt out from the AMI installation will retain the meter they currently have, whether AMR or analog (for those already opted out of AMR). The AMR would be read manually and be subject to a tariffed meter reading charge.<sup>21</sup> Any changes to the opt-out provision would be subject to a future filing by the Company and future review by the Commission. William Hennegan, PPL Manager of Business Integration for AMI, explained that the Company would conduct outreach and include the opt-out process in its customer notification prior to commencement of the new meter installations. Because Pennsylvania did not allow for opt out, the Company will need to develop clear and accessible materials during the customer outreach period. Additional customer outreach methods include automated outbound calls, website information, a dedicated call-in number, and the customer call center.<sup>22</sup>

### **III. Need**

The Company's burden of proof for recovery of costs related to its AMF investments first required a showing of need for the investment. In this case, the Company's primary justification was the age of the meters. Witnesses Walnock and Reder testified that approximately sixty percent of the current AMR meters have reached or are reaching their estimated 20-year design life.<sup>23</sup> According to these witnesses, most utilities utilize advanced metering beyond the AMR technology currently in RI Energy's territory.<sup>24</sup> They asserted that the AMR technology is currently becoming obsolete and will, over time, become unavailable in the marketplace.<sup>25</sup> The AMI technology and related functionality plan will allow customers and the Company more

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<sup>20</sup> Tariff RIPUC No. 2243, Sheets 3-4 (Effective Jan. 1, 2021).

<sup>21</sup> Hr'g. Tr. at 178-80 (July 20, 2023).

<sup>22</sup> *Id.* at 154-56.

<sup>23</sup> Walnock & Reder Test. at Bates 42-43 (Book 1); RI Energy Filing, Book 2 at 21-23.

<sup>24</sup> *Id.* at Bates 44.

<sup>25</sup> *Id.*

visibility into usage and activity on the system. RI Energy also plans to use this information in its distribution system planning and operation activities.<sup>26</sup> The granular information from the AMF investments should provide a better understanding of where on the distribution system various investments are needed to allow for more automated control of the distribution system and, ultimately, the incorporation of distributed energy resources in a more cost effective manner.<sup>27</sup> Furthermore, the witnesses indicated that the AMI technology will also allow for more types of rate structures, including static time of use rates and dynamic time varying rates. Such rates could lead to a more efficient use of the system by customers, resulting in more efficient capital investment plans.<sup>28</sup>

Questions at the hearing explored when and how the Company would utilize the information from the AMF investments. Testimony at the hearing from witnesses Walnock, Constable, and Freitas described how receiving additional information more quickly could be helpful to operating the distribution system. Such information from various communication devices out on the distribution system can be integrated into the advanced distribution management system that RI Energy is installing as part of the merger agreement with PPL. Once this information is available and integrated, certain functions that are now manual can be automated.<sup>29</sup> One example provided was volt var optimization where the witnesses hope to be able to identify and react to high or low voltage conditions on the system even before a customer notices them. Whereas now, the Company distribution operators largely rely on information from its SCADA

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<sup>26</sup> *Id.* at 46

<sup>27</sup> *Id.*

<sup>28</sup> *Id.* at 47-48. RI Energy's evaluation of alternative approaches can be found in its filing, Book 2 at 32-35.

<sup>29</sup> Hr'g. Tr. at 495-503; 512-16.

system and customer calls to identify voltage issues, the additional information will allow for faster and more automated responses.<sup>30</sup>

The new processes will not be instantaneous. Mr. Freitas explained that actually learning how to efficiently use the vast amounts of expected data can be challenging. He stated that “high volume data is always a challenge. You have to really design the human interface with the ADMS so it's optimal for the folks that operate the system.”<sup>31</sup> He advised that the Company would rely on vendors, peer review, and visits with other utilities to learn how they are integrating and using the new data to operate their system.<sup>32</sup> Mr. Freitas was particularly excited about the use of FLISR which stands for Fault Location, Isolation, and Service Restoration. This software application automatically restores power to customers after a fault more quickly than distribution operators can. The availability of more data on a faster schedule than what exists now would allow for this functionality.<sup>33</sup>

No party challenged the need to invest in the new technology. While questioning the urgency of the stated need, the Division ultimately supported the proposal, including the timeline of investments.<sup>34</sup> Additionally, while questioning some of the Company’s assumptions and calculations in the benefit cost analysis, the Division’s witnesses, William Watson and Robin Blanton still calculated an overall positive benefit to cost ratio, albeit significantly lower than what was originally filed by the Company.<sup>35</sup>

The Commission found that the Company has met the burden of showing a reasonable need to replace the current AMRs, primarily due to the age of approximately 60% of the meters. The

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<sup>30</sup> Hr’g. Tr. at 520-22 (Jul. 26, 2024).

<sup>31</sup> Hr’g Tr. at 503.

<sup>32</sup> *Id.*

<sup>33</sup> *Id.* at 532-33.

<sup>34</sup> Watson & Blanton Test. at 10-12, 42.

<sup>35</sup> *Id.* at 33.

need for AMF may not be immediate but based on the evolution of the electric distribution industry across the country, it is reasonable to proceed forward with the most advanced meters and communication network. No intervenor proposed an alternative set of investments.

While it is a stretch to find that the Company needs these meters to manage the system today, these meters should allow the utility to advance many of the goals for the electric system and rate design principles set forth in the Commission's Guidance Document entitled Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a [Rhode Island Energy].<sup>36</sup> Thus, because there is a clear need to replace the current AMRs, based on the evidence presented about the functionalities customers should expect, the Commission authorized the Company to advance the AMF deployment and recover its costs in the manner described in Sections V through VII of this order.

#### **IV. Value Case**

Separate from proving need, to comply with the Commission's requirements in the Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a [Rhode Island Energy], the Company must submit a cost benefit analysis. The Company must also explain how the proposals advance or detract from goals of the electric distribution system and rate design principles. Proposals that result in a positive BCA (greater than 1.0) are not automatically approved if need cannot be proven. Conversely, there may be times when need is proven but the most prudent course of action will not result in a BCA greater than one. In that instance, the Commission needs to balance the need and cost with the cost and benefits of reasonable alternatives. As noted above, in this case, the Company proved

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<sup>36</sup> Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a [Rhode Island Energy] (Docket No. 4600-A); <https://ripuc.ri.gov/eventsactions/docket/4600A-GuidanceDocument-Final-Clean.pdf>.

need to replace the AMRs and made a case that its proposal was a reasonable approach for ratepayers because if executed prudently, it should advance the goals of the distribution system and rate design principles. However, as discussed below, the Company's value case was unreliable.

The Company presented a BCA for its proposal with a BCR more than 3.0. While the BCA was consistent with the Commission's Guidance, the Division challenged several of the assumptions made in RI Energy's value case.<sup>37</sup> Accordingly, the Commission explored those areas extensively through discovery and technical sessions. Based on the evidence presented, the Commission found that the range, magnitude, and value of the BCA was fairly unreliable.

It is not clear that the net benefits advanced by the Company have more than limited value. For example, the value of the faster outage notification, one of the most significant quantified benefits in the BCA, is questionable. Additionally, it is unlikely that the proposed energy insights information that will be presented to customers is really incremental to the information customers receive today as part of the annual Energy Efficiency Plans and budget. Furthermore, once the electric system meets the 100% Renewable Energy Standard, those particular values net to zero. These are just some examples of the weaknesses in the Company's case. These weaknesses are not enough to obviate the need to replace the current AMRs nor do these weaknesses alone justify simply replacing the AMRs. Instead, because of this finding, the Company must be held accountable to the representations it has made in its filing about the values customers will receive. Discussion of the accountability mechanisms can be found in Section VIII of this order.

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<sup>37</sup> Watson and Blanton Test. at 36-37; 42-43.

## V. AMF Capital Investment and Cost Recovery Cap

The Company initially proposed creation of a new cost recovery factor that would allow the Company to recover the actual cost of AMF related capital investments placed into service and actual O&M expense on a semi-annual basis. Because this filing represents an update to the Business Case prepared by National Grid, the Company proposed recovering the costs associated with the preparation of this filing which was necessitated by the acquisition of The Narragansett Electric Company by PPL. Finally, the Company proposed certain offsets to the overall revenue requirement. While the Company filed a budget, there was no limit on the amount of costs that would be recoverable through the new proposed factor.<sup>38</sup>

The Division, instead, recommended the capital investment portion of the AMF investments be recovered through the Infrastructure, Safety, and Reliability factor with a deferral of O&M expense for review in the Company's next rate case.<sup>39</sup> In rebuttal, the Company rejected these recommendations arguing that its proposal was more efficient and cost-effective.<sup>40</sup> On the first day of the hearing, Mr. Bonenberger, President of Rhode Island Energy, testified that the Company would commit to being held to a cost cap based on the budget it had provided in the filing, subject to adjustment if the Commission ordered changes to the Company's investment proposal.<sup>41</sup> Subsequently, the Company filed Statement of Alternative or Additional Positions filed with the Commission on July 13, 2023 wherein it agreed to capital investment cost recovery through the ISR.<sup>42</sup> The Commission ultimately approved a multi-year capital investment cost

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<sup>38</sup> RI Energy Filing (Book 3) at 6-11, 14-15.

<sup>39</sup> Watson and Blanton Test. at 35.

<sup>40</sup> Briggs and Johnson Test. at 5-13.

<sup>41</sup> Hr'g Tr. at 71.

<sup>42</sup> Statement of Alternative or Additional Positions, para. 1.

recovery cap applicable to AMF implementation totaling \$153,217,548 as described more fully below. Treatment of O&M expense is discussed in Section VII.

**a. Capital Spending Recovery Cap and Functionalities**

While the capital investment cap (CapEx Cap) is a limit on cost recovery for capital investments related to implementation of AMF, it is not necessarily a spending cap. The Company has proposed an investment plan designed to provide a certain set of functionalities resulting from project implementation. If the Company agrees to proceed with the AMF deployment subject to all conditions in this Order, the Company will be required to continue spending until the scope of the promised functionalities for the included investments is achieved, regardless of whether the Company's actual spending will exceed the cost recovery cap to achieve those results. The \$153,217,548 comprises CapEx related to Systems Costs, Meter Costs, Network Costs, and Program Costs set forth in Compliance Attachment RR-9, excluding Solar Marketplace (\$664,000); Carbon Footprint Calculator (\$166,000); and C&I Multi-Fam View (\$415,000).<sup>43</sup> Thus, as amended by this decision, customers should expect to pay for meters, systems, and network infrastructure that enables all of the functionalities listed in Figure 6.2, Figure 6.3, and Figure 6.4 "Grid Edge Computing" originally filed in Book 2, Schedule PJW/WR-1.<sup>44</sup> Some of these functionalities include remote meter reading and billing; remote meter configuration and investigation; alerts and alarms (i.e., voltage, usage, billing), both company-facing and customer-facing; near real-time customer data access; and in-home device support.<sup>45</sup>

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<sup>43</sup> The costs are derived from Confidential Attachment H Excel Spreadsheet which provided more granular cost data for each specific investment.

<sup>44</sup> RI Energy Filing (Book 2) at 70-74. The Commission approved advancement of Sense, which was originally listed as one of the future functionalities, and which is categorized as an O&M expense. Company witness Walnock explained that the grid edge computing (Sense) is already installed on the meters when they are delivered. The Company would employ software as a service to enable the functionality in the future. Hr'g. Tr. at 270, 313-14.

<sup>45</sup> *Id.*

The Commission finds that implementing a cap on capital cost recovery aligns with the Attorney General’s court Settlement Agreement with PPL Corporation and PPL Rhode Island Holdings, LLC, (PPL) which requires that the Company—not ratepayers—bear the risk if actual benefits fall short of those projected in National Grid’s prior AMF filing.<sup>46,47</sup> This cost cap augments accountability by ensuring the Company delivers the promised investment and functionality, while also reducing financial risk to ratepayers. Moreover, the Commission considers the cap to be a more efficient and enforceable mechanism than attempting to track benefits over a 20-year period, which would be inherently unreliable. The Settlement also required that the new plan not exceed the cost of National Grid’s proposal, a condition met by the Company and enhanced by the cost recovery cap. While the Commission views the recovery cap as consistent with the Settlement and preferable from an oversight perspective, nothing in this decision limits the Attorney General from seeking enforcement of the court Settlement in the future.

Some intervenors advocated for advancing time varying rates as part of this decision.<sup>48</sup> The Commission, however, did not adopt that position, noting in its discussion that advancement of time varying rates was premature. This is consistent with the Division’s recommendation that time varying rates should be considered in a full rate case or standalone docket. The AMF investment

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<sup>46</sup> On May 4, 2021, PPL, National Grid USA and the Narragansett Electric Company petitioned the Division for approval to transfer ownership of The Narragansett Electric Company to PPL Rhode Island Holdings, LLC. The Division issued an order approving the Petition with conditions on February 23, 2022. The Rhode Island Attorney General appealed the Division’s approval of the transaction between National Grid and PPL. The case was resolved with PPL making additional Commitments beyond those made in the Division proceeding and adopted in the Division’s Order in Docket D-21-09. *Peter Neronha Attorney General of the State of Rhode Island v. Rhode Island Division of Public Utilities and Carriers, et. al.* C.A. No. PC-2022-01095 (2022).

<sup>47</sup> A copy of the Settlement Agreement, inclusive of Exhibit C setting forth PPL’s additional commitments can be found at <https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-10/2207-Settlement%20Agreement%20May19-2022.pdf>.

<sup>48</sup> See Rhode Island Attorney General’s Post-Hearing Statement; RI Energy’s Statement of Alternative or Additional Positions; Opening Statement of CLF (Hr’g Tr. at 65); Closing Statements of OER (Hr’g Tr. at 1169); See e.g., Division statement (Hr’g. Tr. at 39).

will lay the foundation for time varying rates and the Commission will consider such rate design as appropriate.<sup>49</sup>

#### **b. MDMS Cost Recovery**

The Company originally included capital costs associated with a new Meter Data Management System (MDMS) as part of the AMF implementation costs. After a full review of the Company's methodology for allocating MDMS costs to the AMF revenue requirement, the Commission found that those costs will not be eligible for rate base recovery because the Company could not show that the costs allocated to the AMF revenue requirement had properly calculated and excluded costs directly associated with the transition of operations from National Grid to PPL.

In the court Settlement between PPL and the Rhode Island Attorney General, PPL agreed to forego recovery of any transition costs.<sup>50</sup> During the Division's review of the transaction between PPL and National Grid, the Division's witness, Ballaban explained that "[t]ransition costs are a category of acquisition-related costs that Petitioners describe as expenses 'associated with transitioning the ownership, operations and all procedures and active docketed processes from National Grid.'" <sup>51</sup> Mr. Ballaban also explained that transition costs are those associated with separating the Rhode Island operations from the National Grid operations until RI Energy reaches a "steady state," defined as the anticipated costs to operate Narragansett after the transition services expire.<sup>52</sup>

In its filing, Rhode Island Energy included an allocation of 44% of the cost of an MDMS as a component of the AMF project implementation costs.<sup>53</sup> An MDMS is required regardless of

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<sup>49</sup> Division's Response to PUC 1-1.

<sup>50</sup> Settlement Agreement, Exhibit C at para. 1.d.

<sup>51</sup> Docket D-21-09; Ballaban Test. at 16, *citing* PPL's response to Advocacy Section Data Request DIV 2-39.

<sup>52</sup> Docket D-21-09 Ballaban Test. at 5; 16-17 (citations omitted).

<sup>53</sup> This is consistent with how PPL's position was described in the Division's Order approving the transaction between PPL and National Grid: "Regarding [transition] costs, Mr. Bonenberger testified that PPL's transition costs will not result in higher customer rates that arise solely because of the Transaction. He testified that PPL will not

whether RI Energy uses AMR or AMF. According to Company witness Walnock, it's the same foundational MDMS as used in Pennsylvania.<sup>54</sup> He further explained that the way the MDMS was designed, it will work for AMR and then as AMF meters go into service, the MDMS will have the capability to serve those meters.<sup>55</sup> During the evidentiary hearings, Mr. Walnock agreed that the Company never asked for an estimate for an MDMS system without AMF functionality.<sup>56</sup> The Company had also not specifically sought an estimate of what the incremental costs would be for adding AMF functionality to the MDMS required for TSA exit.<sup>57</sup> Finally, the Company had not provided an estimate for the actual incremental cost of having added the AMF functionality to the MDMS except for a calculation based on counting the functionalities.<sup>58</sup> In other words, the Company started with the total number of MDMS functionality requirements. The Company then determined that 99 of the total 224 functionalities, or 44%, were specific to AMF.<sup>59</sup> At the hearing, Mr. Walnock explained that the methodology used was a quantification of the necessary requirements without added complexity of looking at the different costs of each functionality. In other words, the Company assumed that all functionalities cost the same, took the total cost, and allocated 44% to AMF.<sup>60</sup>

The Commission found that this allocation methodology of counting and allocating functionalities without considering cost was insufficient to justify allowing the costs to be added

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seek recovery of duplicative transition costs. Instead, he stated that PPL will only seek recovery of those costs 'that generate incremental benefits for customers.' He added that PPL carries the burden to prove that those incremental benefits support cost recovery before the Commission, and with review and input by the Division. Mr. Bonenberger testified that PPL believes this is a reasonable approach because it is consistent with generally accepted ratemaking principles." (Docket D-21-09 Order at 145, citations omitted).

<sup>54</sup> Tech. Session Tr. at 32 (May 10, 2023).

<sup>55</sup> *Id.* at 68.

<sup>56</sup> Hr'g. Tr. at 405 (Jul. 25, 2023).

<sup>57</sup> *Id.*

<sup>58</sup> *Id.* at 406.

<sup>59</sup> RI Energy's Response to PUC 7-15.

<sup>60</sup> Hr'g. Tr. at 408-10. Because costs allocated to TSA exit can not be recovered, the more of the MDMS costs that can be allocated to AMF, the more the Company could recover. *Id.* at 410.

to rate base. The Company was unable to justify that the 44% allocation was sufficiently aligned with the incremental cost of an MDMS with AMF functionality (AMF cost) versus an MDMS without (excludable transition cost). The Commission considered disallowing cost recovery for the MDMS portion of the project implementation costs. However, there are clearly functionalities within the MDMS that are specific to AMF that would not otherwise have been needed. Thus, the Commission found that those costs will not be eligible for rate base recovery, but instead, shall be amortized over the depreciation period applicable to the asset type and recovered through the ISR without a return.

## **VI. Cost Recovery Mechanism for AMF Capital Revenue Requirement**

As noted above, RI Energy agreed to the Division's position that capital costs be recovered through the ISR factor. As described by Company witness Johnson, the Company would receive approval of the AMF implementation and would not have to justify continuation of the project in its annual ISR filings.<sup>61</sup> She explained that "once those amounts are approved, any approved assets would be subject to an annual reconciliation mechanism that we currently have for the ISR which compares the approved revenue requirement for in-service compared to what's the actual in-service revenue requirement."<sup>62</sup> Company witness Briggs anticipated that "in each ISR plan filing, the review process would be to compare, for that plan period, the amount that the Company has forecasted would be placed in service. That would be compared to the overall timeline. There'd be the opportunity to review to understand if there's any changes compared to ... the overall deployment schedule, if there was any significant changes in that individual year."<sup>63</sup>

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<sup>61</sup> Hr'g. Tr. at 290-91.

<sup>62</sup> Hr'g. Tr. at 289.

<sup>63</sup> Hr'g. Tr. at 291.

While the Commission agreed with the approach of recovering the AMF revenue requirement through the ISR mechanism, the Commission has approved an overall cost recovery cap and is not ruling on the timing of the implementation plan nor on whether delivery of the functionalities may result in costs to the Company that exceed the rate recovery limit. The Company is authorized to seek cost recovery of its capital investments in the categories identified in Record Request 9 through the infrastructure, safety, and reliability process as discretionary investments through the creation of a separate category, subject to the conditions listed in Section V, up to an overall multi-year CapEx cap of \$153,217,548. Capital spending within the scope of Record Request 9 (Project Implementation) that was commenced prior to the ISR Fiscal Year 2025 filing shall be eligible for recovery notwithstanding the fact that the spending was not part of the pre-approved investments within the rules of a prior ISR filing. Equipment will be eligible to be added to plant in service, resulting in the calculation of a revenue requirement when it is put into service and is used.

The AMF revenue requirement will be offset by an accumulated deferral balance arising from the Amended Settlement Agreement (ASA) approved in Docket No. 4770 that constitutes the Multi-Year Rate Plan (MRP) applicable to base distribution rates. As part of its approval of the ASA, the Commission allowed rate recovery of anticipated costs associated with certain “Special Sector Programs” that included Electric Transportation and Storage activities. The ASA contained the following provision:

To the extent the base distribution rate allowances allocated to the program exceed the actual costs incurred, the Company shall record the difference to a regulatory liability account. To the extent the deferral was caused by a reasonable delay in implementation, the deferral shall be applied to program cost incurrence when the program costs are later incurred. To the extent the deferral was caused by a cost reduction or funds not spent for reasons other than a reasonable delay, the deferral shall be held for the benefit of customers and the PUC shall determine how it shall be applied against other programs or costs that otherwise might have been borne by customers. The amount of any such deferral shall incur

carrying charges at the WACC for Narragansett Electric for capital expenses and the customer deposit rate for Narragansett Electric for O&M costs.<sup>64</sup>

The three-year plan set annual pilot deployment and spending goals for the Electric Transportation Initiative (ETI). At an Open Meeting held on August 30, 2022, the Commission reviewed the Rate Year 3 ETI report. The Company had not met the goals nor spent the anticipated funding. No targets had been approved beyond the three-year plan. However, the Company advised that it was planning to pursue additional deployments and spending. At an Open Meeting held on August 30, 2022, the Commission discussed the report noting that it disagreed with the Company's interpretation of the ASA, specifically that it could continue to spend money and set its own targets without seeking Commission approval. In this docket, the Company represented that it was working on a new proposal.

At the hearing in this docket, Company witness Briggs agreed that the funds were not currently committed and funds from these deferrals were available to reduce the AMF revenue requirements if the Commission found it to be reasonable.<sup>65</sup> While the Company may have been working on a plan to spend the accrued dollars, there was no concrete proposal before the Commission<sup>66</sup> and thus, a more appropriate use of the deferrals, net of ongoing costs to complete spending on committed projects, was to offset the revenue requirement associated with the AMF project implementation capital investment. The ongoing annual net cumulative accrual of the Special Sector Deferrals shall only be used to offset the annual Advanced Metering Functionality revenue requirement that is eligible for ISR cost recovery each year.<sup>67</sup>

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<sup>64</sup> Docket No. 4770, Amended Settlement Agreement at 78 (Section 20.d).

<sup>65</sup> Hr'g. Tr. at 387.

<sup>66</sup> Hr'g. Tr. at 384-86.

<sup>67</sup> Identified in PUC 7-13; RR-7; and RR-13.

The AMF factor shall be a fixed annual charge recovered through the respective customer charge. As discussed by the Division’s witnesses, “[n]early all these expenses are created by the number of consumers whose meters will be replaced by AMF meters and are, therefore, customer-related expenses.” The Division was unable to identify expenses that vary by capacity requirements or energy usage. According to the Division’s witnesses, general rate-setting principles would suggest cost recovery would be appropriate “through at least a partial assessment from an increase in the customer charge in each rate class and not rely exclusively on a volumetric charge that carries with it an assumption that the cost varies with energy usage.”<sup>68</sup> The Commission agrees and directs the Company to include a fixed cost factor in the AMF tariff addendum reflecting this decision.

## **VII. Treatment of Operations and Maintenance Expense**

The Company’s implementation plan includes non-capital expenses within each of the capital investment categories. Typically, rate recovery of O&M expenses is considered in a utility’s rate case as part of the utility’s total cost of running their system. Single issue ratemaking is generally disfavored in this and other jurisdictions because it does not consider all operating costs nor does it consider potential savings from new activities that the utility might experience. In addition, as part of a settlement between PPL and the Rhode Island Attorney General, Rhode Island Energy has agreed not to submit a request for a change in base rates until the Company has at least 12 months of operating experience under PPL’s exclusive leadership and after the transition service agreements with National Grid terminate. Thus, the Commission declined to approve the cost recovery mechanism proposed by the Company which would have violated both limitations.

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<sup>68</sup> Watson and Blanton Test. at 36.

Similarly, the Commission declined to approve the Division's proposal to defer the O&M expenses or create a regulatory asset for review in the next base distribution rate case.

Therefore, the Commission directed that neither O&M Expenses incurred during the project implementation period nor run-of-the-business costs incurred prior to new distribution rates being set pursuant to the Company's next base distribution rate case may be deferred or recovered in any new rates. However, the Company may net those costs against the current regulatory liability comprised of specific rate allowances for the AMI Business Case Study and GIS Enhancements (MRP Rate Level Credits) approved in 2018 for the then-anticipated 3-year period of the MRP and which continue to accrue.

As part of the MRP, the Commission allowed rate recovery of anticipated costs associated with National Grid's development of an AMI Business Case Study and GIS Enhancements specifically for three years.<sup>69</sup> Because the initial three-year period has expired, the Company has been continuing to collect the funds in rates and has been recording those funds as a regulatory liability, the disposition of which would be decided in the next base distribution rate case unless the Commission were to order an appropriate disposition prior to that time.<sup>70</sup>

Despite concerns raised by the Attorney General in his post-hearing memorandum,<sup>71</sup> the Commission finds that it is reasonable to use the MRP Rate Level Credits that have already been collected, but which have no continuing cost associated with them, as an offset to the AMF O&M costs prior to setting future rates. Under traditional ratemaking principles, if the funds were not being held in a regulatory liability account, the Company would have use of those funds for this purpose and would also take the risk that the funds would be insufficient to cover the total O&M

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<sup>69</sup> Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Lines 26 and 27.

<sup>70</sup> Hr'g. Tr. (Jul. 25, 2023), at 378-79

<sup>71</sup> RIAG Post-Hearing Mem. at 3.

expenses. Thus, to the extent the eligible O&M expenses incurred during the implementation period and run-of-business period prior to new base distribution rates going into effect, are less than the total accumulated regulatory liability as of that date, the regulatory liability shall remain in effect and the balance shall be applied for the benefit of ratepayers in a manner determined by the Commission. The Company will not be able to seek approval of costs incurred during these periods in excess of the regulatory liability in the next base distribution rate case because such request would violate the principle against retroactive ratemaking. This appropriately balances the interests of the Company and its ratepayers.

### **VIII. Accountability Measures**

As indicated above, the CapEx Cap was only one accountability measure designed to protect ratepayers. Additional accountability metrics are required to address weaknesses in the value case. The metrics will cover three areas: Updates/Additions to Service Quality Mechanisms; Planning and Transparency for Customer-Facing Technologies; and Timely Functional Use of AMF Capabilities. While most of the accountability metrics apply to the AMF implementation, a few will apply prior to dispatch of meters.

In the first area, updating and adding to the current Service Quality Plan, RI Energy shall engage with the Division to negotiate the details and implementation of service quality mechanisms pertaining to meter reading and billing accuracy; outage notification speed improvements; and network communication speed from meter to customer portal; trouble (non-outage) call volume; and customer satisfaction scores. Each metric will include baselines, thresholds, and may include variable penalty structures (e.g., linear scaling, dead bands, shared savings). These metrics are designed to reflect the Company's representation of functionalities that are new or should improve. The proposals shall be filed within three months of the open meeting

decision consistent with the requirements of Ordering Paragraph 17. If the Company and Division do not achieve consensus, the Company shall make the proposal as its own.

While RI Energy has promised increased customer satisfaction and service post-AMF implementation, equally important is continuation of the level of service quality post-TSA exit and during AMF rollout. Prior to AMF rollout, the Company will be exiting the transition period and begin to operate the meter and billing systems without reliance on National Grid's platforms. During this period, the Company will also begin deploying AMF meters and commence meter reading and billing using those meters. Customers should not expect a degradation of the level of service quality they enjoyed prior to TSA exit around meter reading and billing accuracy. Once the new meter installation is complete, new metrics may be considered.

The second area focuses on planning and transparency related to customer-facing technologies, specifically addressing functionalities provided by Green Button Connect, Home Area Networks, and Grid Edge Computing, which are intended to enhance customer access to energy data and facilitate integration with third-party technologies. . The Company's proposals, consistent with Ordering paragraph 16, shall be filed within two months of the start of meter installation and will be considered in a contested case. It will be important to understand the technical issues around data governance and customer access to data. Some parties advocated for a formal stakeholder proceeding to define these items but the Commission, while encouraging stakeholder outreach, declines to order the creation of a formalized group, instead preferring an initial filing and responsive filings to ensure full transparency that can get lost in a settlement.

The third area relating to the timely functional use of AMF capabilities is designed to hold the Company accountable for the functionalities addressed in Section V of this Order. Specifically, the company must demonstrate that it is actively using and/or relying on the functionalities

ratepayers are funding. This includes ADMS Integration; Voltage Notification; Outage Notification; Remote Connect/Disconnect; Theft Detection; the Customer Portal; and Load Disaggregation. The Company shall provide evidence of its usage and/or reliance within the timelines included in Ordering Paragraph 15. The different timelines are based on when functionalities are elected to be available and those closer in time are designed to maintain quality of service while the later timelines are designed to ensure the newer functionalities are available as described by the Company in its filings.

### **IX. Certification**

Because the Commission is authorizing RI Energy to proceed with its plan rather than approving the implementation timeline or chosen technologies as originally requested, when the Company submits its compliance filing, it needs to certify that it is committing to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved CapEx Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed. On December 22, 2023, the Company filed a certification executed by Rhode Island Energy President David J. Bonenberger.<sup>72</sup>

Accordingly, it is hereby,

(25353) ORDERED:

1. Effective January 25, 2023, the following Motions to Intervene were granted: Rhode Island Attorney General; George Wiley Center; Conservation Law Foundation; and also Acadia Center which, on February 24, 2023, voluntarily withdrew from the case.
2. Effective January 25, 2023, the NRG Retail Companies were granted conditional intervention, limiting the scope of their intervention to the issues identified on pages 7-8 of their Reply Brief.

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<sup>72</sup> Compliance Filing at 6-7; [https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-01/2249-RIE-AMF-ComplianceFiling\\_12-22-23.pdf](https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-01/2249-RIE-AMF-ComplianceFiling_12-22-23.pdf).

3. Effective January 25, 2023, Mission:data was granted conditional intervention, limiting the scope of their intervention to the financial and technological aspects of the AMF proposal which relate to Green Button Connect, the Home Area Network, and whether and how the proposed advanced metering functionality affects the market for third party energy management services.
4. There is a need for The Narragansett Electric Company d/b/a Rhode Island Energy to transition its electric distribution operations from the existing automated meter reading-based metering system to a system that utilizes advanced metering functionality.
5. The Narragansett Electric Company d/b/a Rhode Island Energy proposal for a new advanced metering functionality recovery factor is rejected.
6. The Narragansett Electric Company d/b/a Rhode Island Energy is authorized to seek recovery of its capital investments in the categories identified in Record Request 9 through the infrastructure, safety, and reliability process as discretionary investments through the creation of a separate category with an overall multi-year CapEx cap, with the following conditions:
  - a. The Company is not required to prove a need to deploy advanced metering functionality for its electric distribution operations in place of the existing automated meter reading-based metering system;
  - b. The scope of the authorized deployment includes the investments and functionalities, as set forth in Figure 6.2 and Figure 6.3 but shall not include CP:Solar Marketplace, CP:Carbon Footprint Calculator, and CP:C&I and Multi-Family Portfolio View.
  - c. The scope shall also include advancement of load disaggregation & Waveform Analytics and Grid Edge Computing that will be enabled by allowing customers to use Sense by connecting their home area network to the meter as discussed in RR-11 and shall not include acceleration of time varying rates.
  - d. Capital spending within the scope of Record Request 9 (Project Implementation) that was commenced prior to the Infrastructure, Safety, and Reliability Fiscal Year 2025 filing shall be eligible for recovery notwithstanding the fact that the spending was not part of the pre-approved investments within the rules of a prior Infrastructure, Safety, and Reliability filing;
  - e. Recovery of the capital costs incurred for the authorized project implementation period shall be capped in the aggregate at a budget of \$153,217,548 and the Company is directed to file a revised RR-9 and revised Attachment H excel spreadsheet to reflect \$0.00 for the items removed and to show the O&M related to acceleration of Sense.
  - f. Regarding the Special Sector Deferrals identified in the Amended Settlement Agreement and listed in Attachment PUC 7-13, lines 3 and 4, the ongoing annual

net cumulative accrual shall only be used to offset the annual Advanced Metering Functionality revenue requirement that is eligible for ISR cost recovery each year.

7. The Meter Data Management System costs shall not be eligible for rate base recovery; provided, however, 44% of the capital costs associated with the work performed by Landis+Gyr which the Company allocated to AMF shall be amortized over the depreciation period applicable to the asset type and recovered through the ISR without a return.
8. When The Narragansett Electric Company d/b/a Rhode Island Energy submits its compliance filing, it needs to certify that it is committing to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved CapEx Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed.
9. The Narragansett Electric Company d/b/a Rhode Island Energy to file an ISR Addendum to encompass the findings herein for further review by the Commission. The addendum shall include a proposal to recover the revenue requirement associated with the eligible advanced metering functionality CapEx spending to be appropriately allocated to each rate class and recovered through a fixed charge embedded in the applicable customer charge for each rate class for further review by the Commission.
10. Any operation and maintenance expenses (i) relating to the advanced metering functionality project implementation period or (ii) relating to advanced metering functionality “run-the-business” costs, which expenses are incurred during the period prior to new base distribution rates going into effect from the next base distribution rate case may not be deferred or recovered in any new rates.
11. Effective September 27, 2023, through the effective date of the Company’s next base distribution rates, the Company may net operation and maintenance expenses that relate to the advanced metering functionality scope as defined above against the accumulating regulatory liability relating to certain residual revenue requirement items identified in Docket 4770 and enumerated in PUC 7-13, RR-7, and/or RR-13. To the extent that such operation and maintenance expenses during that period are less than the total accumulated regulatory liability as of the date that new base distribution rates go into effect, the regulatory liability shall remain in effect and the balance shall be applied for the benefit of ratepayers in a manner determined by the Commission.
12. The Narragansett Electric Company d/b/a Rhode Island Energy shall file a schedule that updates Attachment PUC 7-13 with actuals through Rate Year Ending August 31, 2023, includes the AMF-related portion of all other grid mod costs identified on line 25, page 7 of 9, Compliance Attachment 1 in the Docket No. 4770 Compliance Filing (Amended Settlement Agreement Book 1) that was identified in SAB/BLJ-1, and provides a forecast through the anticipated effective date of the next base distribution rate case. In addition, the Company shall provide the cumulative balances as of August 31, 2023, in a separate section.

13. The Narragansett Electric Company d/b/a Rhode Island Energy shall update the revised schedule that was just voted on with each annual ISR filing and reconciliation filing and also include a schedule which shows the O&M expenses that have been netted against the rate level credit balance.
14. The effect of the CapEx cap is that the Company will be required to keep spending, even if above the cap, until it achieves the functionalities as set forth in prior motions today.
15. The Narragansett Electric Company d/b/a Rhode Island Energy must comply with the following accountability requirements under the authorization to advance its advanced metering functionality investment plan:
  - a. ADMS Integration: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the meter data is integrated into the ADMS. The company should report on the number of meters installed, time to install the meters, integration with ADMS, and any outliers. Prior to commencing meter installation the company needs to provide the PUC and DPUC definitions of the geographic deployment areas.
  - b. Voltage Notification: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the company has configured real time alerts for over/under voltage and is using the ADMS ping to investigate voltage issue.
  - c. Outage Notification: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for outage notification.
  - d. Remote Connect/Disconnect: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for remote connect, disconnect, service activation, and account transfers.
  - e. Theft Detection: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for theft detection.
  - f. Customer Portal: Company will maintain a customer portal. At a minimum, there should be no discontinuity of customers' ability to access account information and pay bills online.
  - g. Load Disaggregation: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that customers are able to access disaggregated load data. Within 12 months of the conclusion of the deployment period, the company will report on customer access and utilization of disaggregated load data.

16. Within two months of the start of meter installation, The Narragansett Electric Company d/b/a Rhode Island Energy must file plans that address Green Button Connect, Home Area Network, and Grid Edge Computing, as described below. The company may consult with any stakeholder deemed necessary, but the plan must be filed by the company and will be reviewed by the Commission in a contested proceeding.
  - a. Within two months of the start of meter installation, the company must file a Green Button Connect plan that addresses the following:
    - i. For every customer specific item on the bill, whether that same information should be provided through GBC;
    - ii. At a minimum, the company should plan to provide the same data fields and historical information as offered or planned to be offered to its customers in Pennsylvania and Kentucky.
    - iii. For each of the items in (i), whether the underlying customer-specific data (e.g. interval meter reads, voltage) should be provided through GBC;
    - iv. To the extent historical data is provided for (i) and (ii), provide the extent of that data set. Specifically address whether it is appropriate to provide 36 months of electric consumption.
    - v. Whether paragraphs 13.i, 13.ii, and 13.iii should be provided for gas.
    - vi. Whether any additional customer specific data beyond (i) and (ii) should be provided through GBC (e.g. disaggregated load data).
    - vii. Timeline for GBC certification and version of certification.
  - b. Within two months of the start of meter installation, the company must file a Home Area Network plan that addresses the following:
    - i. Version of bring-your-own-device that will be offered to customers, and requirements, if any, on those devices;
    - ii. Access to usage and disaggregation insights;
    - iii. Whether any charges apply to customers or device-makers;
    - iv. Technical standards for local devices;
    - v. Terms and conditions on direct upload of usage data and disaggregation insights.
  - c. Within two months of the start of meter installation, the company must file a Grid Edge Computing plan that presents a framework or terms and conditions for each issue identified in Mission:data Coalition's Post-Hearing Statement section 3, parts (a) through (f).
17. The Narragansett Electric Company d/b/a Rhode Island Energy shall engage with the Division of Public Utilities and Carriers to negotiate the details and implementation of the following service quality mechanisms and file an updated Service Quality Plan for

Commission review and approval in Docket 3628 within three months, or by December 27, 2023. Other parties will be able to intervene in Docket 3628.

- a. Meter reading & billing:
  - i. Monthly percent of meters read is an existing reporting requirement in the service quality plan in Docket 3628.
  - ii. The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period.
  - iii. The service quality mechanism should establish a threshold that represents appropriate performance (e.g. the average of the past three years).
  - iv. The maximum penalty will be imposed for performance 2.5 standard deviations below the threshold.
  - v. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum penalty was determined.
  - vi. The design may or may not be linear, and it may include a dead band.
  - vii. Following the meter installation period, the Company and Division may propose an update to this service quality mechanism in Docket 3628.
  
- b. Faster outage notification:
  - i. The company will be subject to a one-time faster outage notification service quality mechanism 12 months after full project implementation.
  - ii. The service quality mechanism should establish a baseline for outage notification.
  - iii. The maximum penalty will be imposed if evidence shows that the company is notified of outages 0 minutes faster than the baseline.
  - iv. No penalty will be imposed if evidence shows that the company is notified of outages 22 minutes faster than the baseline.
  - v. The metric may be an annual average over all customers or explain why a different metric was chosen.
  - vi. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
  - vii. The mechanism may or may not be linear. Intervals, bins, and dead-bands may be considered.
  - viii. The mechanism may (but is not required to) include a shared savings mechanism for evidence that that the company is notified of outages more than 23 minutes faster than the baseline.
  
- c. Network speed:
  - i. The company will be subject to a one-time or continuous network speed service quality mechanism 12 months after full project implementation.
  - ii. The service quality mechanism should establish a measurement of network speed. The measurement should capture the speed of information from the meter to the

MDMS and back to the customer portal or explain why a different measurement was chosen. The service quality mechanism should establish the time period and scope of the measurement.

- iii. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
  - iv. The company and parties should propose the maximum penalty and threshold. Intervals, bins, and dead bands may be considered.
- d. Trouble, Non-Outage
- i. Trouble, non-outage calls are an existing reporting requirement in the service quality plan in Docket 3628.
  - ii. Within twelve months after meter installation starts, the company will be subject to a service quality mechanism for trouble, non-outage calls.
  - iii. The service quality adjustment should impose scaled penalties for increased trouble, non-outage calls, compared to a baseline. The metric, baseline, minimum, and maximum should be defined and justified.
  - iv. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
- e. Customer satisfaction
- i. Customer satisfaction (customer contact survey) is an existing service quality mechanism in the service quality plan in Docket 3628.
  - ii. Within six months after meter installation starts, the company will be subject to an updated customer contact standard that reflects the company's expectations of higher customer satisfaction. Updates may include, but not be limited to, increasing the minimum percent satisfied threshold, increasing the value of the penalty, and narrowing the dead band.
  - iii. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
18. The Commission authorizes the Company to deploy an AMF-based metering system for the electric distribution business subject to the conditions already ordered.
19. The Company is not required to commence the authorized project implementation. The decision to move forward under the terms of the Commission's authorization rests within the management discretion of the Company; provided, however, if such project implementation is commenced, the conditions set forth by the Commission in this order shall apply.

EFFECTIVE AT WARWICK, RHODE ISLAND ON SEPTEMBER 27, 2023,  
PURSUANT TO AN OPEN MEETING DECISIONS ON JANUARY 25, 2023 AND  
SEPTEMBER 27, 2023. WRITTEN ORDER ISSUED MAY 20, 2025.

PUBLIC UTILITIES COMMISSION



*Ronald T. Gerwatowski*

Ronald T. Gerwatowski, Chairman

*Abigail Anthony*

Abigail Anthony, Commissioner

*John C. Revens, Jr.*  
\*John C. Revens, Jr., Commissioner

\*Commissioner Revens is unavailable for signature due to his retirement.

**Notice of Right of Appeal:** Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the PUC may, within 7 days from the date of the Order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or Order.

# **EXHIBIT 3**

THE NARRAGANSETT ELECTRIC COMPANY  
d/b/a Rhode Island Energy  
RIPUC Docket No. 22-49-EL  
In Re: Advanced Meter Functionality Business Case  
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approach differs from National Grid’s Updated AMF Business Case where achieving automatic power outage notification was anticipated to take a few years given the time that they needed to integrate Last Gasp and “Power-up” meter information with the National Grid’s restoration system. PPL has had the integration operational for several years so the effort at hand is to migrate the pre-existing capability to Rhode Island. Given the availability of ADMS Basic from PPL as a condition of the Acquisition, it facilitates the integration of the outage information from the AMF meters with the operating domain early in the AMF deployment process, thereby making dispatch efficiencies and storm response benefits readily available early in the AMF project.

**Figure 6.2: AMF Deploy Ready Functionalities – Available at TSA Exit**

AMF Functionality	Working Definition
Remote (AMF) Meter Reading & Billing	Reading and billing interval energy usage at standard latency using AMF meters.
Remote Meter Configuration & Investigation	Remote "over-the-air" firmware and software updates & investigation of meter malfunctions. Proactively enabled energy data analytics and reactively enabled by alerts and alarming.
Deployment Exchange	The Meter Deployment solution to status and update the accounts that have been exchanged as part of the AMF deployment. Traditionally this involves exchanging of a "Population file" and synchronizing with the customer system and asset system to reflect the newly installed AMF meter.
AMO Data Driven Operations	Implementation of operational dashboards to manage the AMF Network and associated endpoints. For example, configuration management, firmware levels, endpoint inventory, reading percentages, interval completeness, and overall network health.
Alerts & Alarms: High Temp	Alerting & Alarming - Alerting when configurable internal temperature is reached and sending to work management system for disposition
Proactive Outage Management (Last Gasp / Power-up)	Alerting operations and OMS System when meter experiences an outage or power is restored.
Remote Electric Connect & Disconnect	Activation of remote electric meter switch to turn on/off service; also includes meter tamper alerts and usage analytics.
CP: Customer Portal	Customer-facing usage data availability, usage analytics, normative comparisons, and other data-driven customer experience features. Provide omni-channel access and continuous improvement through an agile and iterative development approach that incorporates on-going customer experience updates.
Customer Outage Alerts	Proactive communication of outages identified in the OMS system to customers.

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### 6.3 AMF Enhanced Functionalities During Meter Deployment

The enhanced functionalities enabled during the Meter Deployment period are described in Figure 6.3 and will deliver benefits to Rhode Island customers throughout the deployment period and beyond.

**Figure 6.3: AMF Functionalities During Meter Deployment**

AMF Functionality	Working Definition
CP: Green Button Connect	Enables customers to transfer energy usage data at a standard latency to authorized third parties.
CEMP - Bill Alerts	Alerts for variety of customer needs. Examples include projected high-bill (consumption and/or costs), prediction of peak demand or usage, and customizable threshold alert at various points during a billing period.
CP: Near Real-Time Customer Data Access	Availability of near real-time raw usage data through the customer portal. This allows 15-minute electrical raw usage data, available within 30-45 minutes, updated with bill quality data within 24 hours.
CP: In-Home Device Support	Enable communications between a customer owned home Device and the AMF meter.
ADMS: Voltage Conservation (Volt-Var Optimization)	Providing interval meter voltage and reactive power data to the ADMS to support conservation voltage reduction (CVR) and Volt-Var Optimization (VVO).
ADMS: Voltage Automated Notification (Sag/Swell)	Configurable real-time alert for momentary under or over voltage on a meter, integrated to ADMS for immediate action.
ADMS: On Demand Voltage Measurement (to ADMS)	ADMS function to ping networked electric devices and meters for voltage measurements.
ADMS-DER: Monitor & Management	Enabling the ability to monitor & manage distributed energy resource (DER) inverter based infrastructure (eg. battery banks, solar PV, net-meters).

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**Figure 6.3: AMF Functionalities Enabled During Meter Deployment (continued)**

AMF Functionality	Working Definition
Network Model Analytics	MDMS functionality to support analysis of the network, identifying outlier issues for investigation (e.g. misassociated meters).
Theft Detection Analytics	MDMS functionality to identify outlier patterns that indicate potential energy theft.
CP: Solar Marketplace	Customer portal functionality that creates an integrated marketplace for customer research of solar PV adoption.
CP: Carbon Footprint Calculator	Customer portal functionality that creates an ability for customers to calculate carbon footprint based on usage data and actions to better manage usage.
CP: C&I and Multi-Family Portfolio View	Customer portal functionality that enables a portfolio view of C&I facilities as well as properties for multifamily unit owners and managers.

#### 6.4 AMF Future Functionality

Figure 6.4 describes when the AMF-enabled future functionality is envisioned (Group 6) to be developed and implemented. Rhode Island Energy will evaluate the future functionalities (e.g., proof of concept) as the Company implements the AMF solution. TVR functionality will depend on regulatory approval of a TVR structure: implementation is expected to lag customer meter installation to provide customers sufficient time to become familiar with their new meter and understand the new interval usage information and pricing options. All AMF meters, network and systems infrastructure must be deployed before TVR can be implemented to support communication of the time varying rates as well as having the ability to process the billing complexity.

# **EXHIBIT 4**

**STATE OF RHODE ISLAND**

**RHODE ISLAND PUBLIC UTILITIES COMMISSION**

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In re: The Narragansett Electric Company	)	
d/b/a Rhode Island Energy’s Advanced	)	Docket No. 22-49-EL
Metering Functionality Business Case	)	

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**THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY’S  
CERTIFICATION**

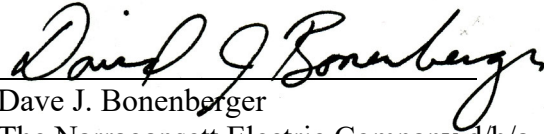
The Narragansett Electric Company d/b/a Rhode Island Energy (“Rhode Island Energy” or the “Company”) respectfully submits this Certification in accordance with Paragraphs 5 and 16 of the Rhode Island Public Utilities Commission’s (the “Commission”) September 27, 2023 Open Meeting motions and votes (“Decision”) approving with conditions the Company’s Advanced Metering Functionality (“AMF”) Business Case, a copy of which is attached as Exhibit 1.

The Company commits to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved Capex Cap (as that term is defined in the Decision) for those investments identified in the scope of the implementation plan as set forth in the Company’s revised response to Record Request 9, which is being submitted contemporaneously with this Certification. The Company further confirms that it will move forward with implementing AMF under the terms of the Commission’s authorization and subject to the conditions set forth by the Commission in the Decision.

----- SIGNATURE PAGE FOLLOWS -----

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

By its President,



Dave J. Bonenberger  
The Narragansett Electric Company d/b/a  
Rhode Island Energy  
280 Melrose Street  
Providence, RI 02907

Dated: December 22, 2023

**CERTIFICATE OF SERVICE**

I hereby certify that on December 22, 2023 I sent a copy of the foregoing to the service list  
by electronic mail.

*/s/ Adam M. Ramos* \_\_\_\_\_

# **EXHIBIT 1**

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

**IN RE: RHODE ISLAND ENERGY ADVANCED           :**  
**METERING FUNCTIONALITY BUSINESS CASE       :**       **DOCKET NO. 22-49-EL**  
**AND COST RECOVERY PROPOSAL                   :**

**OPEN MEETING MOTIONS AND VOTES**

**Finding of Need and Authorization for Deployment**

- (1) Move to find that there is a need for the Company to transition its electric distribution operations from the existing AMR-based metering system to a system that utilizes advanced metering functionality (AMF). RG, AA Vote 3-0

**Capital Cost Recovery through the ISR**

- (2) Move to reject the Company’s proposal for a new AMF recovery factor. RG, AA Vote 3-0
- (3) Move to authorize the Company to seek recovery of its capital investments in the categories identified in Record Request 9 through the infrastructure, safety, and reliability (ISR) process as discretionary investments through the creation of a separate category with an overall multi-year CapEx cap, with the following conditions:
  - (a) The Company is not required to prove a need to deploy AMF for its electric distribution operations in place of the existing AMR-based metering system;
  - (b) The scope of the authorized deployment includes the investments and functionalities, as set forth in Figure 6.2 and Figure 6.3 but shall not include CP:Solar Marketplace, CP:Carbon Footprint Calculator, and CP: C&I and Multi-Family Portfolio View.
  - (c) The scope shall also include advancement of load disaggregation & Waveform Analytics and Grid Edge Computing that will be enabled by allowing customers to use Sense by connecting their home area network to the meter as discussed in RR-11 and shall not include acceleration of TVR.
  - (d) Capital spending within the scope of Record Request 9 (Project Implementation) that was commenced prior to the ISR Fiscal Year 2025 filing shall be eligible for ISR recovery notwithstanding the fact that the spending was not part of the pre-approved investments within the rules of a prior ISR filing;
  - (e) Recovery of the capital costs incurred for the authorized project implementation period shall be capped in the aggregate at a budget of \$153,217,548 and the Company is directed to file a revised RR-9 and revised Attachment H excel

spreadsheet to reflect \$0.00 for the items removed and to show the O&M related to acceleration of Sense.

- (f) Regarding the Special Sector Deferrals identified in the Amended Settlement Agreement and listed in Attachment PUC 7-13, lines 3 and 4, the ongoing annual net cumulative accrual shall only be used to offset the annual AMF revenue requirement that is eligible for ISR cost recovery each year.

RG, AA Vote 3-0

- (4) Move that the Meter Data Management System (MDMS) costs shall not be eligible for rate base recovery; provided, however, 44% of the capital costs associated with the work performed by Landis+Gyr which the Company allocated to AMF shall be amortized over the depreciation period applicable to the asset type and recovered through the ISR without a return. RG, AA Vote 3-0
- (5) When the Company submits its compliance filing, it needs to certify that it is committing to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved Capex Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed. RG, JR Vote 3-0
- (6) Move to direct the Company to file an ISR Addendum to encompass the findings herein for further review by the Commission. The addendum shall include a proposal to recover the revenue requirement associated with the eligible AMF CapEx spending to be appropriately allocated to each rate class and recovered through a fixed charge embedded in the applicable customer charge for each rate class for further review by the Commission. RG, AA Vote 3-0

**Treatment of O&M Expenses Prior to Next Rate Case**

- (7) Move that any operation and maintenance (O&M) expenses (i) relating to the AMF project implementation period or (ii) relating to AMF “run-the-business” costs, which expenses are incurred during the period prior to new base distribution rates going into effect from the next base distribution rate case may not be deferred or recovered in any new rates. RG, AA, Vote 3-0
- (8) Move that effective on the date of this decision through the effective date of the Company’s next base distribution rates, the Company may net O&M expenses that relate to the AMF scope as defined above against the accumulating regulatory liability relating to certain residual revenue requirement items identified in Docket 4770 and enumerated in PUC 7-13, RR-7, and/or RR-13. To the extent that such O&M expenses during that period are less than the total accumulated regulatory liability as of the date that new base distribution rates go into effect, the regulatory liability shall remain in effect and the balance shall be applied for the benefit of ratepayers in a manner determined by the Commission. RG, JR Vote 3-0

- (9) Move to direct the Company to file a schedule that updates Attachment PUC 7-13 with actuals through Rate Year Ending August 31, 2023, includes the AMF-related portion of all other grid mod costs identified on line 25, page 7 of 9, Compliance Attachment 1 in the Docket No. 4770 Compliance Filing (Amended Settlement Agreement Book 1) that was identified in SAB/BLJ-1, and provides a forecast through the anticipated effective date of the next base distribution rate case. In addition, the Company shall provide the cumulative balances as of August 31, 2023 in a separate section. RG, JR Vote 3-0
- (10) Move to direct the Company to update the revised schedule that was just voted on with each annual ISR filing and reconciliation filing and also include a schedule which shows the O&M expenses that have been netted against the rate level credit balance. RG, JR Vote 3-0

## **Accountability Requirements**

- (11) Move that the effect of the CapEx cap is that the Company will be required to keep spending, even if above the cap, until it achieves the functionalities as set forth in prior motions today. AA, JR Vote 3-0
- (12) Move to adopt the following requirements the Company must comply with under the authorization to advance its AMF investment plan:
- ADMS Integration: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the meter data is integrated into the ADMS. The company should report on the number of meters installed, time to install the meters, integration with ADMS, and any outliers. Prior to commencing meter installation the company needs to provide the PUC and DPUC definitions of the geographic deployment areas.
  - Voltage Notification: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the company has configured real time alerts for over/under voltage and is using the ADMS ping to investigate voltage issue.
  - Outage Notification: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for outage notification.
  - Remote Connect/Disconnect: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for remote connect, disconnect, service activation, and account transfers.
  - Theft Detection: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for theft detection.
  - Customer Portal: Company will maintain a customer portal. At a minimum, there should be no discontinuity of customers' ability to access account information and pay bills online.

Load Disaggregation: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that customers are able to access disaggregated load data. Within 12 months of the conclusion of the deployment period, the company will report on customer access and utilization of disaggregated load data.

AA, JR Vote 3-0

- (13) Move that within two months of the start of meter installation, the Company must file plans that address Green Button Connect, Home Area Network, and Grid Edge Computing, as described below. The company may consult with any stakeholder deemed necessary, but the plan must be filed by the company and will be reviewed by the Commission in a contested proceeding.

Green Button Connect: Within two months of the start of meter installation, the company must file a Green Button Connect plan that addresses the following:

- a. For every customer specific item on the bill, whether that same information should be provided through GBC;
- b. At a minimum, the company should plan to provide the same data fields and historical information as offered or planned to be offered to its customers in Pennsylvania and Kentucky.
- c. For each of the items in (a), whether the underlying customer-specific data (e.g. interval meter reads, voltage) should be provided through GBC;
- d. To the extent historical data is provided for (a) and (b), provide the extent of that data set. Specifically address whether it is appropriate to provide 36 months of electric consumption.
- e. Whether (a), (b), and (c) should be provided for gas.
- f. Whether any additional customer specific data beyond (a) and (b) should be provided through GBC (e.g. disaggregated load data).
- g. Timeline for GBC certification and version of certification.

Home Area Network: Within two months of the start of meter installation, the company must file a Home Area Network plan that addresses the following:

- h. Version of bring-your-own-device that will be offered to customers, and requirements, if any, on those devices;
- i. Access to usage and disaggregation insights;
- j. Whether any charges apply to customers or device-makers;
- k. Technical standards for local devices;
- l. Terms and conditions on direct upload of usage data and disaggregation insights.

Grid Edge Computing: Within two months of the start of meter installation, the company must file a Grid Edge Computing plan that presents a framework or terms and conditions for each issue identified in Mission:data Coalition's Post-Hearing Statement section 3, parts (a) through (f).

AA, JR Vote 3-0

- (14) Move to direct Rhode Island Energy to engage with the DPUC to negotiate the details and implementation of the following service quality mechanisms and file an updated Service Quality Plan for Commission review and approval in Docket 3628 within 3 months. Other parties will be able to intervene in Docket 3628.
1. Meter reading & billing:
    - a. Monthly percent of meters read is an existing reporting requirement in the service quality plan in Docket 3628.
    - b. The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period.
    - c. The service quality mechanism should establish a threshold that represents appropriate performance (e.g. the average of the past three years).
    - d. The maximum penalty will be imposed for performance 2.5 standard deviations below the threshold.
    - e. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum penalty was determined.
    - f. The design may or may not be linear, and it may include a dead band.
    - g. Following the meter installation period, the Company and Division may propose an update to this service quality mechanism in Docket 3628.
  2. Faster outage notification:
    - a. The company will be subject to a one-time faster outage notification service quality mechanism 12 months after full project implementation.
    - b. The service quality mechanism should establish a baseline for outage notification.
    - c. The maximum penalty will be imposed if evidence shows that the company is notified of outages 0 minutes faster than the baseline.
    - d. No penalty will be imposed if evidence shows that the company is notified of outages 22 minutes faster than the baseline.
    - e. The metric may be an annual average over all customers or explain why a different metric was chosen.
    - f. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
    - g. The mechanism may or may not be linear. Intervals, bins, and dead-bands may be considered.
    - h. The mechanism may (but is not required to) include a shared savings mechanism for evidence that that the company is notified of outages more than 23 minutes faster than the baseline.
  3. Network speed:
    - a. The company will be subject to a one-time or continuous network speed service quality mechanism 12 months after full project implementation.
    - b. The service quality mechanism should establish a measurement of network speed. The measurement should capture the speed of information from the meter to the MDMS and back to the customer portal or explain why a different measurement

was chosen. The service quality mechanism should establish the time period and scope of the measurement.

- c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
  - d. The company and parties should propose the maximum penalty and threshold. Intervals, bins, and dead bands may be considered.
4. Trouble, Non-Outage
- a. Trouble, non-outage calls are an existing reporting requirement in the service quality plan in Docket 3628.
  - b. Within twelve months after meter installation starts, the company will be subject to a service quality mechanism for trouble, non-outage calls.
  - c. The service quality adjustment should impose scaled penalties for increased trouble, non-outage calls, compared to a baseline. The metric, baseline, minimum, and maximum should be defined and justified.
  - d. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.
5. Customer satisfaction
- a. Customer satisfaction (customer contact survey) is an existing service quality mechanism in the service quality plan in Docket 3628.
  - b. Within six months after meter installation starts, the company will be subject to an updated customer contact standard that reflects the company's expectations of higher customer satisfaction. Updates may include, but not be limited to, increasing the minimum percent satisfied threshold, increasing the value of the penalty, and narrowing the dead band.
  - c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between \$200,000-\$1,000,000), or show why a higher maximum was chosen.

AA, JR Vote 3-0

### **Conclusory Motions**

- (15) The Commission authorizes the Company to deploy an AMF-based metering system for the electric distribution business subject to the conditions already voted on. RG, AA Vote 3-0
- (16) The Company is not required to commence the authorized project implementation. The decision to move forward under the terms of the Commission's authorization rests within the management discretion of the Company; provided, however, if such project implementation is commenced, the conditions set forth by the Commission in the decisions today shall apply. RG, AA Vote 3-0.

# **EXHIBIT 5**

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

**IN RE: PROPOSED GREEN BUTTON CONNECT, : DOCKET NO.: 25-19-EL**  
**HOME AREA NETWORK AND GRID EDGE : :**  
**COMPUTING PLANS : :**

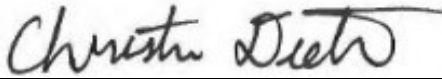
**OPEN MEETING DECISIONS**

1. Grant, in part, and deny, in part, Mission:data Coalition's request for an evidentiary hearing. An evidentiary hearing shall be scheduled, but the scope of the hearing shall be limited as follows:
  - a. The purpose of the hearing will be limited to the following questions:
    - i. Whether the Company should be authorized or required to move forward with the Green Button Connect plan as described in the filing, subject to further review after the Company certifies that the plan is ready for implementation and the Company performs a live demonstration (if such demonstration is requested by the Commission), and
    - ii. Whether the Commission should decline to authorize or require the Company to move forward with the plan as described in the filing, and, as a consequence, whether the Commission should order a reduction in the AMF investment cost cap by the projected cost of Green Button Connect in the amount of \$664,000, as shown in the Company's Attachment PUC 1-4-2-Supplemental in Docket No. 25-54-EL.
  - b. The Commission will not consider any expansions to the Green Button Connect plan which would conflict with the Company's management discretion to offer Green Button Connect functionality that the Company is willing to develop and implement.
2. Deny the Company's motion to strike testimony as moot.

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.



**Christine E. Dieter**

April 29, 2026

**Date**

**The Narragansett Electric Company d/b/a Rhode Island Energy**  
**Docket No. 25-19-EL Proposed Green Button Connect, Home Area Network and Grid**  
**Edge Computing**  
**Service list updated 10/9/2025**

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