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Rhode Island Energy™
a PPL company

July 11, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 22-49-EL-The Narragansett Electric Company d/b/a Rhode Island Energy Advanced Metering Functionality Business Case
Responses to PUC Data Requests – PUC Set 8

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), attached is the electronic version of Rhode Island Energy's responses to the Public Utilities Commission's Eighth Set of Data Requests in the above-referenced matter.[1]

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

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket No. 22-49-EL Service List
John Bell, Division
Leo Wold, Esq.

[1] Per communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by hard copies filed with the Clerk within 24 hours of the electronic filing.

CERTIFICATE OF SERVICE

I certify that a copy of the within documents was forwarded by e-mail to the Service List in the above docket on the 11th day of July, 2023.

Adam M. Ramos, Esq.

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-49-EL Advanced Meter Functionality (AMF)
Service list updated 4/17/2023

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PUC 8-1

Request:

In response to PUC 2-1.d, the Company stated:

> "The Company intends to track this commitment [to "bear the risk of lesser actual realized benefits" than what is assumed in the BCA] by tracking the actual benefits realized from the AMF investment over time. If actual realized benefits are not greater than the costs to implement AMF over the 20-year life of the project – that is, if the actual benefit-cost ratio ends up being less than 1.0 – and therefore the AMF implementation proves uneconomical in the future, then the Company will assess at that time, in consultation with the Division of Public Utilities and Carriers and the Rhode Island Attorney General, a proposal to implement this commitment to be presented to the Commission for review and approval. The Company intends that all the benefits quantified in the business case and included in the BCA fall under this commitment."

(a) Is the Company suggesting that there will be no determination of whether the Company met its commitment until after 20 years have passed? Please explain.

(b) Please define "realized benefits."

(c) Please provide a listing of the benefits the Company intends to track and the dollar values associated with those benefits. (Please also refer to Figures 6.1, 6.2, 6.3, 6.4, and 14.1 of the Business Case where applicable to show how the various functionalities relate to the specific benefits).

(d) Please explain how the Company intends to track the realized benefits.

Response:

(a) No. The Company intends that tracking will begin as soon as benefits begin to be "realized" and will be accumulated and compared to cumulative costs annually.

(b) "Realized benefits" for this discussion means benefits that have been achieved for those benefits that will be tracked, based on the tracking approach described in Attachment PUC 8-2-1.

(c) and (d): Please see Attachments PUC 8-2-1 and PUC 8-2-2 for a full description of the benefits that will be tracked, how they will be tracked, and a spreadsheet showing those benefits and the forecasted benefits (in $Nominal) by year from 2022-2041.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

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PUC 8-2

Request:

In their testimony, on pages 36-37, the Division's witnesses state:

> "The Company provided [cost] estimates for deployment of the AMF meters and the associated systems of $289 million (nominal) and $188 million (PV) with estimated expectations of benefits of $1059 million (nominal) and $729 million (PV). The expected benefits are estimated over a 20-year period, with many accruing in the later years of this time frame due to gradual acceptance by customers, while a significant portion (71%) of the costs are for initial capital investment and are accrued during the first four years of deployment. This leaves the ratepayer open to a high degree of risk that the benefits may not be realized. While we are not proposing that the Company not be allowed to recover prudently incurred costs associated with the installation of an AMF metering system, the Company's Business Case has listed an array of benefits expected to be forthcoming from this system and should be held accountable if the promised benefits fail to materialize. The Company should propose how it plans on assuring the promised benefits accrue to the ratepayers. RIE should develop, for PUC approval, mechanisms that will be used to record and track costs and benefits in a manner that allows the PUC and stakeholders to compare the plan to actual results."

Assuming the Commission were to accept the Division's recommendation, please respond to the following:

(a) For each benefit defined, listed, and subject to tracking, in PUC 8-1, please provide the year in which the benefit is expected to be realized.

(b) Please explain how the Company will determine that the benefit was realized.

(c) Please explain how the Company will determine when the benefit was realized.

(d) Please explain how the Company will quantify the actual value of the benefit that was realized.

(e) Please explain how the Company will compare the value of the realized benefit to the value included in the BCA.

(f) Please explain whether the Company would expect to incur a penalty if the benefits are not realized. If not, why not? If so, please outline an initial proposal.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

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Response:

(a) – (d) Please see Attachment PUC 8-2-1 and Attachment PUC 8-2-2 for a description of when the benefits will be realized, how the Company will determine the benefit was realized, and the calculations that will be used to determine the realized benefits. After the AMF meters are installed, the Company anticipates reporting on the annual and cumulative nominal benefits as they are realized compared to the forecasted nominal benefits.

(e) The Company will compare the value of the realized cumulative benefit on a Nominal basis with the value of the forecast of the cumulative benefits as shown in Attachment PUC 8-2-2.

(f) The Company does not believe a penalty is appropriate if benefits are not realized. First, regardless of whether there are quantifiable realized benefits that exceed costs, the Company believes that moving forward with AMF is still the right thing to do for customers and the State of Rhode Island. The replacement of existing AMR meters will need to take place at some point in the near term, and it is only logical that those meters be replaced with advanced meters. It is also worth noting that replacing the existing meters with the current AMR meters would result in incremental costs with none of the benefits of AMF, rending a benefit-cost ratio of near zero. Second, the Company is delivering on its commitment to bring AMF to Rhode Island, which several stakeholders have acknowledged is a necessary investment to move Rhode Island towards meeting the Climate Mandates. The Company should not, in turn, be penalized for making this investment if all claimed benefits are not realized. Notwithstanding the foregoing, if an accountability metric were to be imposed, then the Company proposes there should be a corresponding financial incentive to the Company if benefits far exceed costs. In determining what penalty should apply, the Company proposes that a penalty should apply only if the AMF project does not reach a 1.0 B/C ratio on a nominal basis based on a forecasted year when the AMF project would break-even. Likewise, the Company should be eligible to receive an incentive if cumulative benefits, which the Company is proposing it will track, exceed the cumulative costs by a certain agreed upon amount or in the event that benefits are achieved sooner than forecasted.

Prepared by or under the supervision of: Philip J. Walnock and Wanda Reder

Rhode Island Energy Approach to Tracking Specific AMF Benefits

A description of when the benefits will be realized, how the Company will determine when the benefit was realized and the proposed calculations that will be used to determine the realized benefits is provided below.

1. These proposed tracking approaches apply only if the AMF Business Case is approved as filed, including the cost recovery mechanism.
2. The Company proposes to track the following benefits, which are organized into categories for ease of calculation and understanding:

Benefit Category	RIE Proposed (Nominal $M)
Tier 1	88.4
Avoided AMR	67.2
Avoided DSP Sensors	23.2
Faster Outage Notification	121.9
Energy Insights	116.4
Unaccounted For Energy	92.1
Total Benefits (nominal $M)	**509.2**
Total Costs (nominal $M)	**289.0**

Tier 1 Benefits

1. Start Year: 2025. The Tier 1 benefits include:

Ben #	Benefit	Nominal ($M)
2	AMR Meter Reading Savings	$ 11.19
3	AMR Meter Reading Vehicle Savings	$ 3.20
5	Reduced Meter Investigations	$ 17.09
6	Remote Metering Benefits	$ 55.63
540	FCS Costs	$ 0.67
541	Interval Meter Reading Costs	$ 0.64

2. The Company anticipates reducing personnel in these categories. The first personnel are anticipated to be reduced in 2025 and the remainder in 2026.
3. The Company projected saving the salary, vehicle cost, phone cost and uniform cost for each employee. All reduced costs associated with personnel attrition such as, actual salaries, fringe, ancillary costs will be tracked.
4. The Company will track the actual costs of the personnel reduced at the time they are reduced for the above items, as relevant.

5. RIE plans to count the full avoided costs of a reduced position from the date it is reduced through 2041 at that date for purposes of tracking and measuring performance toward a >1.0 B/C ratio for the AMF program.
6. The Company also projected that $55,000/year in remote meter reading vendor maintenance cost would be eliminated. The Company will verify the elimination of the vendor maintenance cost after the final headcount has been reduced. At that time, the Company will count the full value of this benefit once the cost has been eliminated for the purpose of determining the B/C ratio of the realized benefits.

Energy Insights

The Energy Savings and Electric Bill Reduction benefits associated with this category are driven by behavioral factors that Energy Insights can influence but are challenging to measure and verify in a reasonable manner. For example, a customer may use Energy Insights and decide to adjust the thermostat on an air conditioning unit. To validate that this adjustment resulted in energy savings the Company or third-party vendor would need to interview the Customer and collect specific information, like air conditioner size, house insulation, thermostat change, etc. This type of data would be required for every change influenced by Energy Insights and would need to be repeated for every customer. A method of this magnitude would not be reasonable. Therefore, the Company is recommending a method which utilizes a modes energy saving assumption per customer who participates in Energy Insights.

1. Start Year: 2026. The benefits tracked in this category are:

Ben #	Benefit	Nominal ($M)
16	Energy Savings: Energy Insights - Electric	$ 31.10
16.5	Electric Bill Reductions: Energy Insights	$ 70.73
17	Monetized CO2 Benefit: Energy Insights	$ 14.58

2. The Company will track the number of independent customers who access the Customer Portal website for the purpose of viewing their energy usage. This number will be summed each year and used to determine the Energy Insights participation.
3. The total energy usage of this population of customers will be summed and will have a 1.5% energy savings factor applied to it to determine the total MWh saved.
4. These MWh will be multiplied by the Company's actual energy price ($/MWh) for that year to determine the value of the Energy Savings: Energy Insights-Electric.
5. These MWh will be multiplied by all volumetric rates other than the energy rate on the customers' bills to determine the Electric Bill Reductions: Energy Insights.
6. These MWh will be multiplied by the Monetized CO2 benefit as presented in the most current AESC report for Rhode Island.
7. The values determined in #4, #5, and #6 will be deemed saved for that year.
8. The process will be repeated each year and the savings will be summed over time.

Avoided DSP Sensors

1. Start year: 2024. The benefits being tracked for Avoided DSP Sensors include:

Ben #	Benefit	Nominal ($M)
23	Avoided DSP Sensors	$ 23.18

2. The benefit associated with Avoided DSP sensors assumes that, rather than 3 sensors per feeder with AMF meter deployment, the Company will only need 1 DSP sensor per feeder, eliminating the need for 2 DSP Sensors/feeder.
3. The Company will establish how many feeders on the system do not have DSP sensors as of 2023. That number will be multiplied by the 2 avoided sensors/meter, and that number will be multiplied by the total cost of a feeder including capex, opex, RTB opex, etc. as described in Attachment H.
4. If the AMF meters are approved, regardless of the communication system, the sensors will not be needed. Therefore, the Company would apply the full Nominal benefit of the avoided sensors as a realized benefit as the meters are deployed.

Avoided AMR Meter Replacement

1. Start year: 2024. The benefits being tracked for Avoided AMR Meter Replacement include:

Ben #	Benefit	Nominal ($M)
100	AMR Meter Replacement - Meter Cost	$ 50.62
102	AMR Electric Meter Installation Cost - Total	$ 16.61

2. The benefits associated with avoiding the costs of replacing AMR meters are based on the AMR meters being at the end of their design life.
3. For the AMR Meter Replacement benefit, the Company will update the prices with the most recent pricing for AMR meters. The Company will use the actual deployment of AMF meter counts to determine when the benefits for not replacing an AMR meter are realized.
4. For AMR Electric Meter Installation Cost, the Company has assumed the AMR meters can be installed at the same cost as the AMF meters. The Company will use these costs and the actual deployment of meter counts to determine when the benefits are realized.

Faster Notification Benefit

1. Start year: 2025. The benefit that will be tracked for Faster Notification Benefit is:

Ben #	Benefit	Nominal ($M)
22	Faster Outage Notification - 50% of Initial Estimate (11 minutes)	$ 121.89

2. The Company will track the difference between when the Company receives notice from the meter that there is an outage and when the first customer calls in to report the outage using the same approach used by PPL Electric Utilities Corporation ("PPL Electric") in Pennsylvania. PPL Electric times stamps both the meter notifications and customer-initiated notifications. The customer calls are also categorized according to whether they are notification calls or request for information calls. The Company will calculate the simple average time difference in minutes for all non-planned outages where both Last Gasp meter alerts and customer-initiated outage notifications were received into the outage management system.
3. The number of minutes calculated in #2 above will be input into the DOE's Interruption Cost Estimator ("ICE") Calculator tool to determine the value of the reduced customer outage time due to the faster notification for the population of customers that have AMF.
4. The values by customer type from the ICE calculator will be adjusted to account for those customers whose MV-90 meters are not being replaced, using the same approach used in the initial Benefit-Cost analysis.
5. The process will be repeated each year and the actual savings will be summed over time to determine total benefits for this category.

Reduced Unaccounted For Energy (UFE)

1. Start year: 2026. The benefits that will be tracked include:

Ben #	Benefit	Nominal ($M)
13	Electricity Theft Reduction	$ 60.61
30	Electromechanical Meter Accuracy	$ 31.47

2. Electricity theft and meter inaccuracies make up the bulk of "non-technical losses", also known as Unaccounted For Energy (UFE). UFE (Unaccounted for Energy) is defined as the delta or difference on an hourly basis (positive or negative) between the Zonal Load and the sum of the individually metered customer hourly loads plus losses and it is reported on FERC Form 1 annually.
3. The Company will compare UFE values over a representative period of time before the AMF meters have been installed to the UFE values after all the AMF meters have been installed.
4. The differential between the "before" and "after" UFE values will be calculated in MWh.
5. The value resulting from #4 will be allocated to residential, commercial and industrial customers based on the ratio of energy usage determined over a representative sample of years.
6. The MWhs savings in each customer class will be multiplied by an average price/kWh as reported by Energy Information Administration to determine the dollar value of the savings.
7. The Company will assume that the dollar value of the savings determined in #6 will continue throughout the remainder of the study period.
8. The annual savings will be "realized" and summed over time to determine cumulative savings.

Attachment PUC 8-2-2

Please see the Excel version of Attachment PUC 8-2-2.

PUC 8-3

Request:

The following relate to the dependency of benefits related to increasing load and DER growth:

(a) Please identify any benefits whose realization is dependent in some way on actual load and DER growth materializing in a manner that is consistent with the load and DER forecast and describe in detail the nature of the dependency between benefits realization and the load/DER forecast.

(b) Please provide the level of certainty for the load and DER forecasts upon which the BCA is based.

Response:

(a) The benefits that are dependent on actual load and DER growth materializing in a manner that is consistent with the load and DER scenario are listed in Attachment PUC 8-3, including a description of the nature of the dependency between benefit realization and the DER growth.

The assumptions Rhode Island Energy used for increasing load and DER were aligned to the scenario used for the Company's Grid Modernization Plan ("GMP") filed with the Public Utilities Commission on December 30, 2022, in Docket No. 22-56-EL.

Specifically, assumed adoption rates of heat pumps, solar PVs, and electric vehicles were determined for the years 2030, 2040, and 2050 to appropriately test the electric system (GMP scenario). The AMF BCA applied the GMP scenario using relevant years for the 20-year AMF study period. Where data were missing because of the milestone forecasting approach used in the GMP, a straight line linear interpolation approach was used to populate data for the missing years. Several values were developed: Summer Peak load, Winter Peak load, and Energy. These Peak and Energy values were developed by starting with a reference load level and adding in or subtracting the impacts of electric vehicles, electric heat pumps and DG, as appropriate.

(b) There was no initial level of certainty determined for the GMP scenario which was used in the AMF Business Case. However, the Company has developed a sensitivity for both the Energy and the System Peak. The sensitivity considered only the reference scenario and Energy Efficiency. No additional electric vehicles, electric heat pumps or DER were included. The result of this sensitivity is that the total energy for the 20-year period is 97% of the energy scenario included in the AMF Business case. The 2042 system peak in this sensitivity ranges from 108% of AMF Business Case Peak in 2022 to 47% of the AMF Business Case Peak in 2041, with an average of 82% of the system peak. Given the incredibly broad range between the two sets of assumptions, and the fact that the results are not extremely different over the 20-year period, one could conclude that there is a significant probability that the actual peak will be within that range.

These percentages of energy and system peak scenarios were applied to the appropriate benefits to determine an estimated value of the benefits under a "Base" scenario rather than the GMP scenario used in the AMF Business Case. These calculations are included in Attachment PUC 8-3.

The overall result is that 80% of the projected AMF benefits and a B/C ratio of 3.1 are achieved assuming a "Base" scenario rather than the GMP scenario.

Attachment PUC 8-3

Please see the Excel version of Attachment PUC 8-3.

PUC 8-4

Request:

For each functionality and related benefit the Company expects to be realized as a result of the choice of AMI 2.0 that are not available with AMI 1.0, please specifically explain how the Company will track those investment costs and those realized benefits. Please provide a listing of the date when those functionalities will produce realized benefits. Further explain whether, if the additional functionality is never used and, therefore, provides no additional benefit, the Company expects that that it would be at risk for the investment that had been included in a capital cost recovery mechanism. If not, why not? If so, please detail the financial risk the Company expects it would face. Please note that an answer that the Commission could conduct a prudence review will not be responsive.

Response:

The Company describes the incremental capability of AMF 2.0 relative to AMF 1.0 in its response to PUC 7-1. The Company considered incremental benefits qualitatively, not quantitatively, when determining whether to propose AMI 2.0 or AMI 1.0. The Company performed a qualitative analysis for incremental benefits of AMI 2.0 and determined that the relatively small incremental cost for AMI 2.0, as explained in the Company's response to PUC 6-4 Supplemental, made AMI 2.0 the preferred proposition compared to AMF 1.0. The Company did not structure its benefits according to incremental functionality available between AMF 1.0 and AMF 2.0 because technology, costs, and benefits did not align in that manner.

Costs Tracking

The Company cannot disentangle incremental costs by incremental functionality, so cost tracking will be done for the entire AMF project. See Attachment 8-2-1 for a more detailed description of the approach where annual and cumulative costs will be tracked on a nominal basis and compared to the AMF Business Plan. Cost tracking results will be provided in a breakdown summary and submitted in an annual AMF Program Report that is accompanied by a mid-year project status update meeting that begins after AMF approval.

AMF 2.0 Functionality

AMI 2.0 functionality is derived from a combination of grid-edge intelligent meters, a more robust RF communication network and systems that work together to offer new value from near real time access to information. Near real time information is an attribute unique to AMF 2.0 that provides new grid-facing and customer-facing functionality. Some of the AMI 2.0 functionality was quantified in the Business Case costs and benefits, and other functionality was defined as futuristic where it could be pursued pending evaluation and subsequent regulatory approvals.

Below, the Company explains how incremental AMI 2.0 realized benefits are to be tracked with a date by which those functionalities are assumed to start producing benefits. Start dates that are dependent upon additional regulatory approval are noted. Beyond the metrics stated below, as noted in Attachment 8-2-1, at any time during the tracking period, if the Company discovers a new benefit that can be tracked and has monetary value for the customer or the utility, that benefit will be included in total achieved benefits for purposes of the break-even calculation after appropriate review.

- ***Proactive Outage Management*** - AMF 2.0 incrementally provides greater network bandwidth for on-demand inquiries and the option to implement Signature Recognition as a future functionality. These incremental functionalities primarily contribute to proactive outage assessment to improve Faster Outage Notification. The Company described the tracking process for the Faster Outage Notification in Attachment PUC 8-2-1, which begins in 2025.
- ***Comprehensive Voltage Management -*** AMF 2.0 incrementally provides for increased sampling and greater analytics, which provides new visibility and insight to system voltage issues in near real time. The added granularity and near real time timeliness of the data also will increase optimization accuracy for VVO/CVR. This incremental functionality contributes to the benefits of energy savings and monetized CO2 benefit (realized beginning in 2026), and system capacity and transmission capacity benefits (realized beginning in 2029). Realizing VVO benefits is dependent upon approval of specific GMP investments available through the ISR process or other regulatory approval processes. The number of feeders with VVO/CVR will be a standard reporting metric that would contribute to resultant energy savings and the monetized CO2 reduction analysis.
- ***Energy Insights -*** AMF 2.0 provides near real-time information, which will be more useful than information received four to six hours later for customers who want to manage their energy usage. While not all the benefits from Energy Insights are attributed to AMF 2.0, the Company believes that AMF 2.0 will enable some of the Energy Insights savings. The Energy Insights benefits include Energy Savings, Bill Savings for participating customers, and Monetized CO2 savings, all of which begin in 2026. The Company has described how it will track Energy Insights benefits in Attachment PUC 8-2-1.
- ***Whole House TOU/CPP and Electric Vehicle TVR -*** AMF 2.0's near real-time information functionality will be important for the development and implementation of more sophisticated Time-Varying-Rates. The benefits estimated in the AMF BCA were

based on more simplistic TVR rate constructs that do not require near-real time data, but the more sophisticated TVR approaches that incorporate variable incentives that fluctuate with time will not work with AMF 1.0. The Company is not proposing to track these benefits at this time because tracking benefits will ultimately depend on the rate construct that is approved and implemented.

- ***Grid Observability and DER Monitor and Manage -*** The Company did not estimate benefits associated with Grid Observability and DER Monitor and Manage as these benefits are much more difficult to quantify. Grid Observability is the ability for operators to see what is happening on the system in near-real time, which provides timely information and knowledge to correct for conditions that might otherwise go to failure. This cannot happen if the operators do not get the information until four to six hours after the events take place. Similarly, DER Monitor and Manage will rely on near-real time visibility enabled by version 2.0 meters.
- ***Distributed Intelligence -*** The Company did not estimate benefits associated with Distributed Intelligence because the technology is in the early stages of deployment and Rhode Island Energy has not finalized the details around the grid edge computing approach. Distributed Intelligence is anticipated to enable future benefits because the internal computing capacity embedded in the meter can perform a variety of functions and analysis at the grid-edge which creates a platform that can enable a range of use cases not possible with AMI 1.0. Distributed intelligence can also mitigate technology obsolescence risk by enabling new benefits and expanding AMI functionality that can be incorporated over time through software updates rather than through additional hardware or costly infrastructure solutions. Suitable tracking metrics will be defined in conjunction with use cases that utilize Distributed Intelligence.

Financial Risk for the Company

Please see the Company's response to PUC 8-2(f) for a description of the Company's position on financial risk.