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Rhode Island Energy™
a PPL company

February 3, 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
<u>Responses to PUC Data Requests – PUC Set 3</u>

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 Third Set of Data Requests in the above-referenced matter, with the exception of PUC 3-18, which remains pending and will be submitted under separate cover.[1]

This filing includes a Motion for Protective Treatment of Confidential Information in accordance with Commission Rules of Practice and Procedure 1.3(H)(3) and R.I. Gen. Laws § 38-2-2(4) for the following Excel spreadsheet attachments to the Company's responses: Attachment PUC 3-2, Attachment PUC 3-3, Attachment PUC 3-8, Attachment PUC 3-10, and Attachment PUC 3-22-1. Accordingly, the Company has provided the Commission with these Excel spreadsheets by way of a secure, confidential link.

[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.

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.

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 3rd day of February, 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 1/30/2023

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STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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

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

On November 18, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") submitted its Advanced Metering Functionality Business Case (the "AMF Business Case") in the above-captioned docket. With this motion, the Company respectfully requests that the PUC provide confidential treatment and grant protection from public disclosure of certain attachments to its responses to the PUC's Third Set of Data Requests Nos. 3-2, 3-3, 3-8, 3-10, and 3-22-1. The Company has ensured that its narrative responses may be made public and asks for confidential treatment only of the attachments, which are spreadsheets containing information pulled directly from the AMF Benefit-Cost Analysis ("BCA") spreadsheet in Excel format ("BCA Model"), for which the Company has sought confidential treatment, commercially sensitive pricing and salary information, and/or vendor pricing information for which the Company has certain confidentiality obligations.

For the reasons described below, the Company respectfully requests that the PUC provide confidential treatment and grant protection from public disclosure of the confidential, competitively sensitive, and proprietary information described, as permitted by Rule 1.3(H)(3) of the PUC Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) ("Rule 1.3(H)"), and R.I. Gen. Laws § 38-2-2(4)(B).

I. BACKGROUND

On November 17, 2022, Rhode Island Energy submitted its AMF Business Case to the PUC. In that filing, the Company submitted its BCA Model as part of Attachment H and has moved for confidential treatment of the BCA Model. The PUC has maintained confidential treatment of the BCA Model pending a ruling on the Company's motion.

As explained in the previous motion, the BCA Model contains confidential and proprietary commercial and financial information that the Company ordinarily would not share with the public. Specifically, the BCA Model includes confidential pricing information from Rhode Island Energy's third-party vendors, assumptions regarding salaries for positions that have not yet been filled, and information with respect to which Rhode Island Energy has confidentiality obligations, including confidential information provided to Rhode Island Energy by National Grid USA ("National Grid") and Rhode Island Energy's third-party vendors.

The attachments that are the subject of this Motion include excerpts of information from the BCA Model, as well as additional confidential pricing information from the Company's vendors. The information in the attachments has not been aggregated or otherwise anonymized—it contains some of the same confidential, commercially sensitive, and proprietary information included in the BCA Model, as well as vendor pricing information. It is not feasible to redact the attachments in such a way that they could be made public without jeopardizing sensitive interests—that type of redaction would make the attachments unreadable.

Therefore, the Company respectfully requests that Attachments PUC 3-2, 3-3, 3-8, 3-10, and 3-22-1 be afforded confidential treatment pursuant to Rule 1.3(H).

II. LEGAL STANDARD

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

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

III. BASIS FOR CONFIDENTIALITY

There are three bases for confidentiality with respect to the Company's responses to the PUC's Third Set of Data Requests that are the subject of this motion: (1) Attachments PUC 3-3 and 3-8 contain information for which National Grid previously sought protective treatment in Docket No. 5113, and National Grid provided the information to the Company confidentially; (2) Attachments PUC 3-2 and 3-10 contain information pulled directly from the BCA Model that constitutes the Company's "commercial or financial information" to which the APRA public disclosure requirements do not apply, *see* R.I. Gen. Laws § 38-2-2(4)(B); and (3) Attachment PUC 3-22-1 contains proprietary commercial and financial information relating to the Company's business operations and the business operations of the its vendors, which information satisfies the APRA exception found in R.I. Gen. Laws § 38-2-2(4)(B) because the Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding, but does not customarily share this type of information with the public.

A. Attachments PUC 3-3 and 3-8 contain information for which National Grid sought protective treatment in Docket No. 5113, and the Company seeks to preserve that confidentiality.

The attachments provided in response to PUC Data Request Nos. 3-3 and 3-8 include information from a spreadsheet that contains a summary view of National Grid's BCA, which was provided to the Company as a confidential document from National Grid. In Docket No. 5113, National Grid sought protective treatment for this information pursuant to R.I. Gen. Laws § 38-2-2(4)(A)-(B) and Rule 1.3(H)(3). National Grid provided this information confidentially to the Company and requested that the Company protect it as confidential. The Company therefore requests that the PUC maintain the confidentiality of this information by providing protective treatment to Attachments PUC 3-3 and 3-8.

B. Attachments PUC 3-2 and 3-10 contain confidential information from the BCA Model.

The attachments provided with responses to PUC Data Requests Nos. 3-2 and 3-10 all include information pulled directly from the BCA Model. For example, Attachment PUC 3-2 is a spreadsheet containing information about "hourly rates," "annual salary," "equipment vendor maintenance bill," when explaining the "benefit inputs." This information is commercially sensitive and not of the type that the Company would normally make publicly available. Similarly, Attachment PUC 3-10 is a spreadsheet explaining the anticipated operations and maintenance savings by year, following the full deployment of meters; this information includes specific information about the cost of meter-installation services, as well as the implementation costs for the AMR demonstration period, among others. Attachment PUC 3-10 also contains confidential information provided to the Company by National Grid.

This information constitutes confidential, commercially sensitive, and proprietary information that the Company would not normally make public and the publication of which could put the Company at a disadvantage. Furthermore, it is not feasible to redact the attachments in such a way that they could be made public without jeopardizing sensitive interests—that type of redaction would make the attachments unreadable. Therefore, the Company respectfully requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to these two attachments, on the grounds that they contain "trade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." R.I. Gen. Laws § 38-2-2(4)(B).

C. Attachment PUC 3-22-1 contains commercially sensitive and proprietary financial information relating to the business operations of the Company and its vendors.

The attachment provided in response to PUC Data Request No. 3-22-1 is a spreadsheet outlining the costs of Meter Data Management System ("MDMS") implementation and maintenance for the next twenty years in both AMF and non-AMF scenarios. This document reflects pricing information from the Company's third-party vendors. The Company ordinarily does not make this information available to the public because disclosure of the information contained in Attachment PUC 3-22-1 may impact the Company's ability to negotiate favorable pricing for Rhode Island customers in the future and could put the Company's vendors at a competitive disadvantage. Rather, the Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding. Therefore, this information also satisfies the APRA exception found in Gen. Laws § 38-2-2(4)(B).

The Company respectfully requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the attachment to its response to PUC Data Request No. 3-22-1 because these sensitive commercial interests constitute "commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." R.I. Gen. Laws § 38-2-2(4)(B).

Accordingly, Rhode Island Energy respectfully requests that the PUC grant protective treatment to the Attachments PUC 3-2, 3-3, 3-8, 3-10, and 3-22-1 and take the following actions to preserve their confidentiality: (1) maintain Attachments PUC 3-2, 3-3, 3-8, 3-10 and 3-22 as confidential indefinitely; (3) not place the these five attachments on the public docket; and (4) disclose Attachments PUC 3-2, 3-3, 3-8, 3-10, and 3-22-1 only to the PUC, its attorneys, and staff as necessary to review this docket.

IV. CONCLUSION

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

Respectfully submitted,

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

By its attorney,

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Dated: February 3, 2023

CERTIFICATE OF SERVICE

I hereby certify that on February 3, 2023, I sent a copy of the foregoing to the service list by electronic mail.

/s/ Adam M. Ramos

PUC 3-1

Schedule Comparison

Request:

Schedule SAB/BLJ-1 (pages 1 and 2) contains an illustrative summary of the revenue requirements which is in a format similar to the summary of revenue requirements used by National Grid in Docket No. 5113 (Schedule RRPP-2). While the schedules have the same format, there are some changes in the cost categories in lines 1 through 9 of the first column in the RI Energy schedule. Please explain the difference in RI Energy's cost categories from those in National Grid's schedule. This question is not asking about dollar values.

Response:

On Schedule SAB/BLJ-1 (pages 1 and 2), in the capital section Lines 1 through 3, there is an additional cost category of "303 – Intangible Software" compared to National Grid USA's ("National Grid") Schedule RRPP-2 in Docket No. 5113. These represent capital software costs that will be incurred and recorded on the books of Rhode Island Energy, whereas at National Grid the similar costs would have been incurred and recorded on the books of National Grid USA Service Company, Inc. ("Service Company") and allocated to the Rhode Island business as Service Company Rents (931), which would be reflected as an O&M cost in National Grid's Schedule RRPP-2, Line 10.

On Schedule SAB-BLJ-1 (pages 1 and 2), the O&M section Lines 5 through 9, there is an additional cost category of "921 – Outside Services." These costs are primarily related to systems and as described above, these would be directly included in Rhode Island Energy's direct O&M costs, whereas at National Grid, the similar costs were shown on National Grid Schedule RRPP-2, Page 1, Line 11, as Service Company costs ("921/923 – Office Supplies/Outside Services").

Lastly, National Grid's Schedule RRPP-2, included an additional O&M line "901 – Supervision" (Line 4). These costs appear to be mainly associated with business/program management. On Schedule SAB/BLJ-1, Pages 1 and 2, the Company included similar costs in O&M cost category "921 – Outside Services," as the work would be completed by outside vendors. When the actual costs are incurred and recorded on the books, if the costs are charged instead to a different O&M account such as 901 – Supervision, the Company would include that account for recovery in the same manner as if they had been booked to account 921. For O&M costs, there is no difference in the revenue requirement whether the costs are recorded in different O&M cost categories that are presented on Schedule SAB/BLJ-1.

Prepared by or under the supervision of: Stephanie A. Briggs

PUC 3-2

Benefit Cost Analysis - General

Request:

Please provide electronic copies of any excel worksheets, with all formulas in tact, that Rhode Island Energy used to determine the BCA from the original National Grid filing which is being compared against the BCA filed in this case by Rhode Island Energy.

Response:

Please see Confidential Attachment PUC 3-2-1, which is a copy of National Grid USA's ("National Grid") Benefit- Cost model in Excel format, which the Company filed confidentially in Docket No. 5113 while under National Grid ownership. Also, please see Attachment PUC 3-2-2, Attachment PUC 3-2-3, Attachment PUC 3-2-4, and Attachment PUC 3-2-5, which are four files developed by National Grid and used, in part, by Rhode Island Energy to develop its BCA assumptions. Other than these files, National Grid did not provide PPL Corporation and/or Rhode Island Energy personnel with any additional excel worksheets or details associated with National Grid's development of the inputs and assumptions used to develop Confidential Attachment PUC 3-2-1. Rhode Island Energy's costs and benefits were calculated based on Rhode Island Energy's assumptions as described in Attachment H of the AMF Business Case. In some cases, where benefits calculated by National Grid were either very small or based on internal National Grid documents, Rhode Island Energy utilized National Grid's values.

Prepared by or under the supervision of: Ann R. Coldren, Flora Flygt, Wanda Reder, and Philip J. Walnock

Attachments PUC 3-2-1 to PUC 3-2-5

Please see the Excel versions of Confidential Attachments PUC 3-2-1 to PUC 3-2-5.

PUC 3-3

Benefit Cost Analysis - General

Request:

Referring to Attachment C of the Business Case, the Commission is interested in understanding the extent to which Rhode Island Energy's higher forecast of benefits than the benefits forecasted by National Grid is the result of Rhode Island Energy updating the benefit calculation with current information, identifying a benefit that was present but was not identified by National Grid, and/or achieving a higher benefit because Rhode Island Energy is proposing to implement AMF more effectively than National Grid.

Using the list of specified benefits indicated in each of the figures/tables found in Section 11.5 of the business case (beginning with Figure 11.8 on Bates page 144), provide a listing of those benefits with three columns containing the following information for each benefit:

(1) stating the benefit value forecasted by National Grid,

(2) stating the benefit value forecast by Rhode Island Energy, and

(3) indicating whether any difference in value between (1) and (2) was a result of

(a) an update to current information,

(b) a new benefit identified by Rhode Island Energy that was associated with and achievable from the program, but not identified by National Grid in their filing,

(c) a new benefit forecasted to be achievable by Rhode Island Energy because of more effective, experienced, or innovative implementation than National Grid, and/or

(d) another applicable reason.

NOTE: If there was a combination of reasons, please provide a best estimate of the likely % contribution of each to the difference.

Response:

Please see Confidential Attachment PUC 3-3 for the requested information. All the tables are included with the exception of Figure 11.8. Figure 11.8 shows groupings of individual benefits.

Prepared by or under the supervision of: Flora Flygt and Wanda Reder

Because the benefits are grouped in Figure 11.8 and because the differentials for individual benefits can be either positive or negative, assigning a particular percentage reason to each one of the benefit groups is infeasible. The remaining figures in Section 11.5 depict the individual benefits for each of the grouped benefits in Figure 11.8, and the reasons for the differentials are provided in Confidential Attachment PUC 3-3.

Prepared by or under the supervision of: Flora Flygt and Wanda Reder

Attachment PUC 3-3

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

PUC 3-4

Benefit Cost Analysis - General

Request:

Beginning on Bates page 136, the Company explains the differences in benefits originally calculated by National Grid, compared to the benefits now calculated by Rhode Island Energy. In order to provide an illustrative comparison based on the same assumptions and timing between the National Grid and Rhode Island Energy BCAs, please provide a hypothetical recalculation of the BCA based on Rhode Island Energy's forecasted cost incurrence, using the same benefit values that were used by National Grid in its filing in Docket 5113 for those benefits that are present in both BCAs.

Response:

The Nominal benefits using National Grid USA's ("National Grid") benefit values for the benefits that are present in both BCAs are $805.5 million and the NPV savings ($2022) are $401.7 million. When these National Grid benefits are divided by Rhode Island Energy's costs of $289.0 million Nominal and 188.0 million NPV ($2022), the B/C ratios are 2.8 Nominal and 2.1 NPV. Rhode Island Energy's benefits for the benefits that are present in both BCAs are $737.2 million nominal and $510.4 million NPV ($2022), resulting in B/C ratios of 2.6 Nominal and 2.7 NPV when using Rhode Island Energy's benefit values and costs.

The tab labeled 1-RIE BenTrack in Attachment H (AMF BCA spreadsheet) has more detailed information on the benefits that were calculated by Rhode Island Energy versus National Grid. Columns A-J contain the nominal and NPV ($2022) savings for each benefit Rhode Island Energy considered. The benefits are sorted into Utility, Direct Customer, Societal and Transfer Payments. Columns M-V have the same information for National Grid's benefit values.

PUC 3-5

Benefit Cost Analysis - General

Request:

In National Grid's AMF proposal, the Company proposed to deploy AMF-enabled gas modules on its gas meters.

(a) Did the National Grid BCA include costs related to the deployment of AMF-enabled gas modules on its gas meters? If so, please quantify.

(b) Does the Rhode Island Energy BCA include the costs for either a smart gas meter deployment or AMF-enabled gas module deployment? If so, please quantify.

(c) If the National Grid BCA included costs related to the deployment of AMF-enabled gas modules on its gas meters, but the Rhode Island Energy BCA did not include any costs for either a smart gas meter deployment or AMF-enabled gas module deployment, did Rhode Island Energy remove those costs from the National Grid BCA cost estimate that was compared to the Rhode Island Energy BCA cost estimate for purposes of comparing the cost of AMF between the two proposals? If not removed, please explain why not.

(d) If such AMF-enabled gas module costs were removed from the National Grid BCA, please provide the total cost that was removed from the analysis.

Response:

(a) Yes, the BCA submitted by the Company while under the ownership of National Grid USA ("National Grid") included approximately $30.06M NPV and $52.11M Nominal in costs related to the deployment of AMF-enabled gas modules on its gas meters.

(b) No, the Rhode Island Energy BCA does not contain costs for deployment of either AMF gas meters or AMF-enabled gas modules because the AMF Business Case does not include a proposal to deploy AMF-enabled gas meters.

(c) Yes, Rhode Island Energy removed costs related to the deployment of AMF-enabled gas modules on its gas meters from the National Grid BCA cost estimate that was compared to the Rhode Island Energy BCA cost estimate for purposes of comparing the cost of AMF between the two proposals.

Prepared by or under the supervision of: William J. Hennegan and Philip J. Walnock

(d) The total cost that was removed from the National Grid BCA is approximately $30.06M NPV and $52.11M Nominal.

PUC 3-6

Benefit Cost Analysis - General

Request:

Referring to Figure 11.32 of the Business Case relating to sensitivities and the reference to "CO2 Savings" on Bates page 171, please provide a more complete explanation for the description and rationale which states: "The value of CO2 savings is both significant to the analysis and uncertain."

Response:

The non-embedded total value of CO2 savings included in the BCA is $210.9 million nominal and $158.3 million NPV ($2022), which makes it a significant portion of the overall savings. The value is uncertain because there are many different methods for estimating the value of non-embedded CO2 savings (e.g., social cost of carbon, global Marginal Abatement cost, Northeast Marginal Abatement Cost approaches) and those different methods yield different values.

PUC 3-7

Benefit Cost Analysis - General

Request:

Referring to Figure C2 of the Business Case (Bates page 230), it appears from the figure that National Grid showed a higher nominal "Utility Savings" benefit than Rhode Island Energy. Please explain why there appears to be a significant difference.

Response:

The difference between National Grid USA's ("National Grid") nominal "Utility Savings" benefit and Rhode Island Energy's nominal "Utility Savings" benefit as shown on Figure C2, Attachment C of the AMF Business Case (Bates Page 230) is the result of two main factors: (1) the differences in the avoided energy costs and avoided capacity costs between the AESC 2018 Report, which National Grid used, and the AESC 2021 Report, which Rhode Island Energy used; and (2) the discount rate that Rhode Island Energy utilized as compared with the discount rate that National Grid utilized. These differences are discussed in more detail on Bates Page 136 of 200 of the Company's AMF Business Case:

> There are three major differences that can be observed looking at Figures 11.4 and 11.5. The first is that the Utility benefits are very similar from a Net Present Value ($2022) perspective, but the nominal benefits are significantly different. This result is driven by two main factors. First, National Grid's nominal Utility benefits are higher due to differences in the avoided energy and avoided capacity costs between the AESC 2018 Report and the AESC 2021 Report; energy values were 25-30% higher and capacity values were 40-45% higher in the 2018 report. Second, Rhode Island Energy discounted the Utility benefits that utilized the AESC values by 2% rather than 6.97% that National Grid used. The Company chose the 2% discount rate because the avoided cost values developed in the AESC 2021 report are shown in $2021dollars ("real" dollars) regardless of which year was being forecast. Rhode Island Energy inflated these values by 2% to develop the nominal values and discounted them by 2% to get back to the initial "real" values, adjusted to be $2022. This would create a much higher NPV than discounting those values at 6.97% but discounting values that are already "real" is not appropriate in calculating net present values. Hence, National Grid's Utility nominal benefits are higher because

the energy and capacity costs were higher in 2018 and their NPVs are lower because they discounted them by 6.97% rather than 2%.

Prepared by or under the supervision of: Flora Flygt and Wanda Reder

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PUC 3-8

Cost Estimates, O&M Savings, and Revenue Requirement

Request:

Referring to Figure 11.4 (Bates page 135) and page 38 of Attachment H, please provide a table identifying the source(s) by cost component (as found in the materials filed with the Commission by National Grid in Docket 5113) that were used by Rhode Island Energy to determine that National Grid's nominal "AMF Costs" were $289.4 million. If the information was not derived from sources that were filed with the Commission by National Grid in Docket 5113, please provide copies. If any of the costs were adjusted or updated from the original sources by Rhode Island Energy, please indicate the adjustments or changes.

Response:

No adjustments were made to determine the National Grid USA ("National Grid") nominal value of $289.35 million because it can be found in cell M211 within the tab titled "Electric Summary within the National Grid Benefit-Cost Analysis" of the excel spreadsheet filed as part of National Grid's Benefit-Cost Analysis (Attachment E). This information is part of the Confidential BCA spreadsheet provided to Rhode Island Energy by National Grid. Confidential Attachment PUC 3-8 is a summary view of the National Grid Electric Summary tab displaying National Grid's cost components that total $289.35 million nominal.

Attachment PUC 3-8

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

PUC 3-9

Cost Estimates, O&M Savings, and Revenue Requirement

Request:

Comparing revenue requirement Schedule SAB/BLJ-1 to the AMF Model (tab "7-RIE Paybk)," the annual total O&M and capex investments do not appear to align. One example is the assumed meter investment totals in the first four years within the AMF Model which appear to be materially different than the meter investment totals assumed through Year 4 in the revenue requirements schedule (see page 3 of 27, line 1; Bates 23).

(a) Please explain the apparent mismatch between the annual cost incurrence assumed in the revenue requirement schedule with the annual cost incurrence identified in the AMF Model for both capex and O&M.

(b) If the revenue requirement in Schedule SAB/BLJ-1 used different cost estimates than what was used in the AMF Model, please provide a schedule showing the differences between the cost incurrence and timing assumed in the revenue requirement and the cost incurrence and the timing assumed in the AMF Model.

Response:

(a) and (b) Schedule SAB/BLJ-1 used the same cost estimates and spending timeline assumptions that were used in the AMF BCA Model; however, there are a few differences between the two models resulting in what appears to be a misalignment between the annual cost incurrence amount in Schedule SAB/BLJ-1 and annual cost incurrence amount identified in the AMF BCA Model for capex and O&M. First, the revenue requirement model is based on when the investments are placed into service while the AMF BCA Model represents the spend per year. For example, the majority of the software costs are spent over a multi-year period and the amount of spend per year is reflected in the AMF BCA Model. However, the revenue requirement calculation only captures the total spend once the asset is placed into service and the total amount for all spend years would be reflected in the revenue requirements model in the year that it is placed into service. Secondly, the AMF BCA Model represents costs per calendar year period while the revenue requirement represents the recovery periods, which are proposed as twelve-month periods of October to September, which results in different amounts between the models. Lastly, from a cost category perspective, the AMF BCA Model shows the Program costs as its own category while the revenue requirements model includes the capital Program costs within the other capital categories, resulting in higher costs within the categories of Meters, Networks and Systems in the revenue requirement model. The second and third differences are the main drivers for the differences seen between the two models in the meter investment category.

Prepared by or under the supervision of: Stephanie A. Briggs

PUC 3-10

Cost Estimates, O&M Savings, and Revenue Requirement

Request:

On page 61 of the testimony of Walnock & Reder lines 19-20, it states: "Following meter installation, O&M savings are anticipated in every year thereafter."

(a) Please provide the approximate date when the Company expects full deployment of meters to be complete, assuming hypothetically that approval of the AMF proposal is effective on and after October 1, 2023.

(b) Please provide a schedule which identifies all the categories of annual O&M cost savings that the Company forecasts will result from the AMF deployment in each year following approval of the AMF plan, consistent with the Company's project timeline and cost savings assumed in the BCA, including an estimate of the annual O&M cost savings in each year for which O&M cost savings are assumed within the BCA and the revenue requirement schedule SAB/BLJ-1.

Response:

(a) Based on a hypothetical approval date of on or after October 1, 2023, the Company anticipates the full deployment of meters to complete around the end of Q1 or the beginning of Q2 2026. As the hypothetical approval date extends beyond October 1, 2023, the date of full deployment of meters would extend correspondingly further into 2026.

(b) Please see attached spreadsheet, Confidential Attachment PUC 3-10, which includes all the O&M savings by year included in the BCA. As noted on Confidential Attachment PUC 3-10, 80 percent of the savings from Benefits 2, 3, 5, 6, 540 and 541 have been reflected as a reduction to the revenue requirement schedule SAB/BLJ-1.

Attachment PUC 3-10

Please see the Excel version of Confidential Attachment PUC 3-10.

PUC 3-11

Cost Estimates, O&M Savings, and Revenue Requirement

Request:

Referring to Figure 11.1 on Bates page 133 indicating $354.7 million of "Utility Benefits" and the itemization of "Utility Savings" shown on Bates page 142, please provide a schedule which shows year by year (i) the total revenue requirement for the AMF project (separately showing O&M and revenue requirement from capex) and (ii) the utility savings (if any) forecasted to be experienced in each of the same years from which the $354.7 million of Utility Benefits were derived. Please also separately show the breakdown of the utility savings by category (by year) as such savings were categorized on Bates page 142.

Response:

(i) Please see Schedule SAB/BLJ-1, Pages 1 and 2 for the total revenue requirement for the AMF project year by year broken down by capital on Line 4, O&M on Line 9 and the Opex benefits on Line 13.

(ii) For the utility savings forecast by year, see Attachment PUC 3-11. The attachment provides the total annual utility savings and the annual utility savings broken out by program and benefit. The annual savings are shown in nominal dollar savings, which total $529.7 million, which, when discounted back at the appropriate discount rates, total the $354.7 million NPV ($2022) discussed above.

PUC Data Request 3-11, Part (ii)

Rhode Island Energy Benefits - Annual

Total Nominal Utility Savings by Year

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
529.7	1.30	6.47	32.74	27.91	9.37	11.98	14.11	17.15	18.45	19.69	20.50	19.37	26.14	27.73	32.65	36.79	42.17	48.08	56.01	61.07

Figure 11.11: Energy Insights Benefits

Energy Insights Savings

Nominal Savings by Year

Ben #	As of November 12, 2022	Nominal (\$M)	NPV (\$M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
16	Energy Savings: Energy Insights - Electric	31.10	23.42	-	-	-	-	0.34	0.69	1.05	1.45	1.48	1.56	1.67	1.77	1.91	2.08	2.26	2.45	2.68	2.95	3.27	3.49
714	Energy DRIPE Benefit: Energy Insights	1.18	0.71	-	-	0.05	0.12	0.15	0.16	0.15	0.13	0.11	0.09	0.06	0.04	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01
17	Monetized CO2 Benefit: Energy Insights	14.58	10.86	-	-	-	-	0.07	0.22	0.31	0.46	0.73	0.74	0.75	0.63	0.81	1.08	1.17	1.27	1.38	1.51	1.67	1.77
	Total Energy Insights Utility Savings	**46.86**	**35.00**	**-**	**-**	**0.05**	**0.12**	**0.57**	**1.07**	**1.51**	**2.04**	**2.32**	**2.38**	**2.48**	**2.45**	**2.75**	**3.18**	**3.45**	**3.73**	**4.07**	**4.47**	**4.95**	**5.27**

Figure 11.10 Volt/Var Optimization (VVO) and Conservation Voltage Reduction (CVR) Savings

VVO/CVR Utility Benefits

Nominal Savings by Year

Ben #	As of November 12, 2022	Nominal (\$M)	NPV (\$M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
14	Energy Savings: VVO/CVR	34.06	25.61	-	-	-	-	0.32	0.65	0.98	1.35	1.72	1.80	1.92	2.02	2.17	2.34	2.53	2.73	2.96	3.23	3.57	3.78
15	Monetized CO2 Benefit: VVO/CVR	16.05	11.96	-	-	-	-	0.07	0.20	0.29	0.43	0.84	0.85	0.86	0.72	0.92	1.22	1.32	1.41	1.52	1.66	1.82	1.92
730	Trans Capacity Benefit: VVO/CVR	4.16	3.05	-	-	-	-	-	-	-	0.05	0.10	0.16	0.22	0.28	0.28	0.31	0.35	0.39	0.43	0.48	0.54	0.58
40	System Capacity Benefit: VVO/CVR	3.07	2.25	-	-	-	-	-	-	-	0.04	0.08	0.11	0.16	0.20	0.26	0.21	0.25	0.27	0.31	0.35	0.40	0.44
712	Energy DRIPE Benefit: VVO/CVR	0.85	0.42	-	-	-	-	0.02	0.05	0.07	0.08	0.09	0.10	0.10	0.09	0.08	0.06	0.04	0.03	0.02	0.01	0.00	0.00
731	Capacity DRIPE Benefit: VVO/CVR	0.46	0.17	-	-	-	-	-	-	0.00	0.00	0.01	0.02	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.03
729	Dist Capacity Benefit: VVO/CVR	0.27	0.20	-	-	-	-	-	-	-	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.04
	Total VVO/CVR Utility Benefits	**58.93**	**43.65**	**-**	**-**	**-**	**-**	**0.41**	**0.90**	**1.34**	**1.95**	**2.85**	**3.04**	**3.30**	**3.37**	**3.77**	**4.21**	**4.56**	**4.91**	**5.32**	**5.81**	**6.40**	**6.78**

Figure 11.14 Electric Vehicle Time-Varying Rate Benefits

EV/TVR Utility Benefits - Opt-In (20%)

Nominal Savings by Year

Ben #	As of November 12, 2022	Nominal (\$M)	NPV (\$M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
720	Trans Capacity Benefit: EV TVR	58.90	41.89	-	-	-	-	0.01	0.07	0.23	0.43	0.59	0.80	1.04	1.35	1.76	2.28	3.92	5.16	6.78	8.91	11.69	13.87
25	System Capacity Benefit: EV TVR	43.41	30.86	-	-	-	-	0.01	0.05	0.15	0.31	0.43	0.56	0.77	0.98	1.61	1.57	2.73	3.66	4.89	6.52	8.69	10.49
721	Dist Capacity Benefit: EV TVR	3.79	2.70	-	-	-	-	0.00	0.00	0.01	0.03	0.04	0.05	0.07	0.09	0.11	0.15	0.25	0.33	0.44	0.57	0.75	0.89
24	Energy Shift Benefits: EV TVR	2.08	1.51	-	-	-	-	0.00	0.01	0.01	0.01	0.02	0.04	0.15	0.13	0.08	0.11	0.14	0.17	0.22	0.27	0.33	0.37
726	Capacity DRIPE Benefit: EV TVR	1.32	0.50	-	-	-	-	-	-	-	-	-	-	-	0.19	0.25	0.31	0.24	0.17	0.09	0.05	0.02	0.01
722	Monetized CO2 Benefits: EV TVR	0.26	0.17	-	-	-	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
727	Energy DRIPE Benefit: EV TVR	0.22	0.12	-	-	-	0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.00	0.00	0.00	-	-	-
	Total EV/TVR Utility Benefits	**109.96**	**77.76**	**-**	**-**	**-**	**0.01**	**0.04**	**0.17**	**0.45**	**0.83**	**1.13**	**1.49**	**2.07**	**2.78**	**3.84**	**4.44**	**7.31**	**9.51**	**12.44**	**16.34**	**21.50**	**25.65**

Figure 11.15: Benefits from Avoided AMR Costs

Avoided AMR Utility Costs

Nominal Savings by Year

Ben #	As of November 12, 2022	Nominal (\$M)	NPV (\$M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
100	AMR Meter Replacement	50.62	33.44	-	0.93	16.78	13.13	1.00	1.45	1.04	1.35	1.09	1.36	1.14	1.17	1.28	1.26	1.38	1.35	1.56	1.31	1.34	0.69
102	AMR Electric Meter Installation Cost - Capex Portion	16.11	10.61	-	0.29	5.30	4.16	0.32	0.46	0.33	0.43	0.35	0.43	0.37	0.38	0.41	0.41	0.45	0.44	0.51	0.43	0.44	0.22
102.5	AMR Electric Meter Installation Cost - Opex Portion	0.50	0.33	-	0.01	0.16	0.13	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01
105	AMR Demonstration Period Cost	1.34	1.09	-	-	1.34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	Call Center Implementation Cost	1.06	0.84	-	0.05	0.50	0.52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
124	AMR Internal Project Management Leadership - Capex Portion	2.85	2.33	-	0.92	0.95	0.98	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
126	AMR Electric Meter Installation Cost - Cost of Removal (COR)	0.92	0.63	0.02	0.02	0.31	0.24	0.02	0.03	0.02	0.03	0.02	0.03	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.01	-	-
129	AMR Internal Project Management Leadership - Opex Portion	0.90	0.84	0.90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
134	AMR Inventory Equipment Cost	1.08	0.76	0.02	0.02	0.40	0.30	0.02	0.03	0.02	0.03	0.02	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.01	-	-
139	Account Maintenance & Operations Implementation Cost	1.05	0.84	-	0.07	0.49	0.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
203	CMS Deployment Center, Facility Cost	2.43	1.92	-	-	1.20	1.23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
204	CMS Back Office & Clerical Cost	2.32	1.87	0.10	0.33	0.93	0.96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Service Representative Tools / Uniform Cost	0.25	0.20	-	-	0.19	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206	Installed Meter Quality Checks	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
207	CMS Deployment Coordination Labor Cost	2.54	2.04	-	0.49	1.01	1.04	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	CMS Field Installer Initial Training	0.92	0.78	-	0.45	0.47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	CMS Cellular Communication Cost	0.11	0.09	-	-	0.06	0.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Handheld Devices Cost	0.07	0.05	-	-	0.07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
400	Customer Engagement Plan Cost	3.05	2.35	0.26	0.94	0.56	0.28	0.25	0.17	0.15	0.14	0.12	0.12	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
401	Customer Engagement Plan Labor Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
505	MDS System Development Testing	0.07	0.06	-	0.05	0.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
540	FCS Costs	0.67	0.29	-	-	-	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05
541	Interval Meter Reading Costs	0.64	0.30	-	-	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
	Total Avoided Utility AMR Costs	**89.49**	**61.68**	**1.30**	**4.57**	**30.75**	**23.64**	**1.67**	**2.22**	**1.64**	**2.04**	**1.68**	**2.05**	**1.64**	**1.68**	**1.84**	**1.82**	**1.99**	**1.95**	**2.24**	**1.87**	**1.89**	**1.02**

Figure 11.16: Remote Meter Reading Benefits

Ben #	Remote Metering Utility Benefits As of November 12, 2022	Nominal ($M)	NPV ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
				Nominal Savings by Year																			
6	Remote Metering Benefits	$ 55.63	$ 24.73	$ -	$ -	$ -	$ 1.37	$ 2.81	$ 2.88	$ 2.95	$ 3.02	$ 3.10	$ 3.17	$ 3.25	$ 3.33	$ 3.41	$ 3.49	$ 3.58	$ 3.67	$ 3.76	$ 3.85	$ 3.95	$ 4.04

Figure 11.17: Avoided Digital Signal Processor (DSP) Sensors Benefit

Ben #	DSP Sensors (Utility Benefit) As of November 12, 2022	Nominal ($M)	NPV ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
				Nominal Savings by Year																			
23	Avoided DSP Sensors	$ 23.18	$ 14.36	$ -	$ 1.90	$ 1.94	$ 1.98	$ 2.02	$ 2.06	$ 2.11	$ 2.15	$ 2.20	$ 2.24	$ 2.29	$ 0.23	$ 0.24	$ 0.24	$ 0.25	$ 0.25	$ 0.26	$ 0.26	$ 0.27	$ 0.27

Figure 11.13: Whole House TOU/CPP Benefits

Ben #	Whole House TOU/CPP Utility Benefits - Opt-In (20%) As of November 12, 2022	Nominal ($M)	NPV ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
				Nominal Savings by Year																			
26	System Capacity Benefit: Whole House CPP	$ 38.84	$ 28.58	$ -	$ -	$ -	$ -	$ 0.06	$ 0.33	$ 0.79	$ 1.16	$ 1.20	$ 1.15	$ 1.23	$ 1.21	$ 3.20	$ 2.73	$ 3.13	$ 3.56	$ 4.02	$ 4.52	$ 5.08	$ 5.45
27	Energy Shift Benefits: Whole House Time-of-Use (TOU)	$ 1.26	$ 0.48	$ -	$ -	$ -	$ -	$ 0.01	$ 0.02	$ 0.06	$ 0.06	$ 0.03	$ 0.04	$ 0.04	$ 0.08	$ 0.12	$ 0.08	$ 0.09	$ 0.10	$ 0.11	$ 0.13	$ 0.14	$ 0.16
27.5	System Capacity Savings: Whole House Time-of-Use (TOU)	$ 7.10	$ 5.23	$ -	$ -	$ -	$ -	$ 0.01	$ 0.06	$ 0.14	$ 0.21	$ 0.22	$ 0.21	$ 0.22	$ 0.22	$ 0.59	$ 0.50	$ 0.57	$ 0.65	$ 0.74	$ 0.83	$ 0.93	$ 1.00
28	Monetized CO2 Benefit: Avoided Energy - Whole House TOU	$ 0.09	$ 0.04	$ -	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ -
709	Capacity DRIPE Benefit: Whole House CPP	$ 3.42	$ 2.48	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.12	$ 0.12	$ 0.12	$ 0.25	$ 0.28	$ 0.32	$ 0.36	$ 0.40	$ 0.44	$ 0.49	$ 0.52
710	Energy DRIPE Benefit: Whole House TOU	$ 0.13	$ 0.06	$ -	$ -	$ -	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 0.01	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
716	Trans Capacity Benefit: Whole House CPP	$ 58.72	$ 43.25	$ -	$ -	$ -	$ -	$ 0.14	$ 0.57	$ 1.31	$ 1.78	$ 1.82	$ 1.83	$ 1.84	$ 1.85	$ 3.88	$ 4.42	$ 4.99	$ 5.58	$ 6.21	$ 6.86	$ 7.60	$ 8.01
717	Dist Capacity Benefit: Whole House CPP	$ 3.40	$ 2.51	$ -	$ -	$ -	$ -	$ 0.01	$ 0.03	$ 0.08	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.23	$ 0.26	$ 0.29	$ 0.32	$ 0.36	$ 0.40	$ 0.44	$ 0.46
718	Trans Capacity Benefit: Whole House TOU	$ 0.97	$ 0.71	$ -	$ -	$ -	$ -	$ 0.00	$ 0.01	$ 0.02	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.06	$ 0.07	$ 0.08	$ 0.09	$ 0.10	$ 0.11	$ 0.13	$ 0.13
719	Dist Capacity Benefit: Whole House TOU	$ 0.26	$ 0.19	$ -	$ -	$ -	$ -	$ 0.00	$ 0.00	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.03	$ 0.03	$ 0.04
	Total Whole House TOU/CPP	**$ 114.18**	**$ 83.52**	**$ -**	**$ -**	**$ -**	**$ 0.00**	**$ 0.24**	**$ 1.03**	**$ 2.42**	**$ 3.38**	**$ 3.43**	**$ 3.52**	**$ 3.63**	**$ 3.66**	**$ 8.37**	**$ 8.38**	**$ 9.51**	**$ 10.71**	**$ 11.98**	**$ 13.33**	**$ 14.85**	**$ 15.77**

Figure 11.18: Field Investigations Benefits

Ben #	Reduced Field Investigations (Utility Benefits) As of November 12, 2022	Nominal ($M)	NPV ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
				Nominal Savings by Year																			
5	Reduced Meter Investigations	$ 17.09	$7.63	$ -	$ -	$ -	$ 0.43	$ 0.89	$ 0.90	$ 0.92	$ 0.94	$ 0.96	$ 0.98	$ 1.00	$ 1.02	$ 1.05	$ 1.07	$ 1.09	$ 1.11	$ 1.14	$ 1.16	$ 1.19	$ 1.21

Figure 11.19: AMR Meter Reading Benefits

Ben #	AMF Meter Reading Benefits As of November 12, 2022	Nominal ($M)	NPV ($M)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
				Nominal Savings by Year																			
2	AMR Meter Reading Savings	$ 11.19	$4.97	$ -	$ -	$ -	$ 0.27	$ 0.56	$ 0.58	$ 0.59	$ 0.61	$ 0.62	$ 0.64	$ 0.65	$ 0.67	$ 0.69	$ 0.70	$ 0.72	$ 0.74	$ 0.76	$ 0.78	$ 0.80	$ 0.82
3	AMR Meter Reading Vehicle Savings	$ 3.20	$1.43	$ -	$ -	$ -	$ 0.08	$ 0.16	$ 0.17	$ 0.17	$ 0.17	$ 0.18	$ 0.18	$ 0.19	$ 0.19	$ 0.20	$ 0.20	$ 0.21	$ 0.21	$ 0.21	$ 0.22	$ 0.22	$ 0.23
Total	**Total AMF Meter Reading Benefits**	**$ 14.38**	**$ 6.40**	**$ -**	**$ -**	**$ -**	**$ 0.35**	**$ 0.73**	**$ 0.74**	**$ 0.76**	**$ 0.78**	**$ 0.80**	**$ 0.82**	**$ 0.84**	**$ 0.86**	**$ 0.88**	**$ 0.90**	**$ 0.93**	**$ 0.95**	**$ 0.97**	**$ 1.00**	**$ 1.02**	**$ 1.05**

PUC 3-12

Cost Estimates, O&M Savings, and Revenue Requirement

Request:

Referring to the testimony of Walnock & Reder, p. 46 of 84 (lines 3-5), it states: "The Company will be performing work associated with Systems, Meters, RF Network Equipment and Planning functions totaling approximately $8 million prior to receipt of regulatory approval for the AMF Business Case." On lines 20-21, the testimony also states: "The Company has included the $8 million in its calculation of the proposed revenue requirement, as shown in the schedules to the pre-filed testimony of Company witnesses Stephanie Briggs and Bethany L. Johnson."

(a) With respect to the quoted statement, what is the date the witnesses assume that regulatory approval would be received?

(b) Please provide a schedule which itemizes the $8 million by category, estimated cost, and timing of cost incurrence, distinguishing between O&M and capex.

(c) Please provide a companion schedule which isolates and provides the annual revenue requirement that the Company proposes to recover in rates that is associated with the $8 million of cost incurrence that occurs prior to regulatory approval of the AMF Business Case.

(d) Please identify the pages, columns, and lines in Schedule SAB/BLJ-1 which illustrate the recovery of the referenced $8 million.

(e) To the extent that the $8 million of expenditures reflects capex, please provide a schedule showing the date that each capital asset associated with the relevant expenditure was or is forecasted to be placed into service, the total capex investment associated with the capital asset, a description of the capital asset, when the Company proposes to commence recovery of the annual revenue requirement for each of the investments, and the annual revenue requirement for each.

(f) To the extent that the $8 million of expenditures reflects O&M, please explain why recovering past expenditures of O&M prior to regulatory review and approval does not violate the rule of retroactive ratemaking where there was no tariff in effect or any other orders of the Commission issued prior to cost incurrence which authorized such retroactive recovery.

Prepared by or under the supervision of: Philip J. Walnock, William Hennegan and Stephanie A. Briggs

Response:

(a) The quoted statement above assumed receipt of regulatory approval by June 30, 2023, which is the date by which the Company requested the PUC approve the AMF Business Case.

(b) The $8 million is made up of $0.786 million of Network costs and $7.211 million of systems costs as shown on Attachment PUC 3-12-1. All costs are capex.

(c) Please see Attachment PUC 3-12-2 for the annual revenue requirement that the Company proposes to recover in rates associated with the $8 million cost incurrence prior to regulatory approval. The majority of the costs shown on Attachment PUC 3-12-1 are part of multi-year costs for the assets and will not be included for recovery until the asset is placed into service.

(d) The revenue requirement amounts shown on Attachment PUC 3-12-2 in response to part c are included in the total revenue requirements on Schedule SAB/BLJ-1, Pages 5 and 6 for system costs and Pages 7 and 8 for network costs.

(e) Please see Attachment PUC 1-12 to the Company's response to data request PUC 1-12 (capex network costs) and Attachment PUC 1-11 to the Company's response to data request PUC 1-11 (capex software costs) for the recovery year that the capital investments are anticipated to be placed into service, the total capital investment, a description of the capital asset and when the Company proposes to begin recovery of the revenue requirement of each of the investments. The Company did not prepare a separate annual revenue requirement for each of the individual investments on Attachment PUC 3-12-1. For the $0.786 million of network costs and $7.211 million of systems costs presented on Attachment PUC 3-12-1, the Company has calculated the annual revenue requirement for the total of each cost category of network and software as shown on Attachment PUC 3-12-2.

(f) All of the $8 million is capex and does not include any O&M costs.

Prepared by or under the supervision of: Philip J. Walnock, William Hennegan and Stephanie A. Briggs

The Narragansett Electric Company d/b/a Rhode Island Energy
AMF Plan - Network and System Costs

Network Hardware

Network Hardware CapEx Item Description	CY 2022	Jan – June 2023	Total
Network Development and Testing - Ancillary Equipment	$ -	$ 1,284	$ 1,284
(Routers) Hardware - Routers	$ -	$ 286,780	$ 286,780
Additional Transformers Required - Material	$ -	$ 27,873	$ 27,873
(High Capacity Gateways) Hardware - Cellular Backhaul Modem	$ -	$ 28,068	$ 28,068
(High Capacity Gateways) Hardware - High Capacity Network Gateway	$ -	$ 65,492	$ 65,492
(Standard Capacity Gateways) Hardware - Network Gateway	$ -	$ 201,870	$ 201,870
Network Development and Testing - Routers, Gateways, Antennas, Modem	$ -	$ 1,896	$ 1,896
(High Capacity Gateways) Hardware - Telecom Cabinet	$ -	$ 46,780	$ 46,780
Poles (for Gateways & Equipment)	$ -	$ 126,322	$ 126,322
Total	**$ -**	**$ 786,367**	**$ 786,367**

Systems

Systems Capex Item Description	CY 2022	Jan – June 2023	Total
ADMS & OMS	$ 53,847	$ 312,313	$ 366,160
Data Lake	$ 39,655	$ 76,667	$ 116,322
Data Lake - SI VENDOR	$ 36,543	$ 70,649	$ 107,192
Advanced Analytics	$ 25,358	$ 49,025	$ 74,383
Network Model Analytics / AGA	$ 11,746	$ 22,709	$ 34,455
Customer Service Software	$ 84,113	$ 390,285	$ 474,398
Customer Portal	$ 53,950	$ 281,619	$ 335,569
Customer Outage Alerts	$ 16,600	$ 86,652	$ 103,252
Green Button Connect	$ 33,200	$ 173,304	$ 206,504
Bill Alerts	$ 16,600	$ 86,652	$ 103,252
CyberSecurity (Implement)	$ 21,251	$ 139,687	$ 160,938
SI Vendor - CyberSecurity (Implement)	$ 56,096	$ 368,739	$ 424,835
SI Vendor - Headend (Implement)	$ 100,653	$ 778,381	$ 879,034
Software as a Service (SaaS) Vendor - Headend	$ 201,418	$ 1,557,630	$ 1,759,048
SI Vendor - MDMS (Implement)	$ 40,710	$ 236,117	$ 276,827
Software as a Service (SaaS) Vendor - MDMS	$ 92,480	$ 536,383	$ 628,863
Middleware - SI Vendor (Implement)	$ 59,943	$ 347,669	$ 407,611
Middleware (Implement)	$ 22,754	$ 131,973	$ 154,727
PPL PMO Oversight (IT) - AMF Implementation PMO	$ 140,618	$ 457,000	$ 597,619
Total	**$ 1,107,534**	**$ 6,103,455**	**$ 7, 210,989**

The Narragansett Electric Company
AMF Plan
Illustrative Revenue Requirement - Electric Telecommunication Equipment (397)

	Source		Program Year 1 & 2 AMF Recovery Year 1 (a)	Program Year 3 AMF Recovery Year 2 (b)	Program Year 4 AMF Recovery Year 3 (c)	Program Year 5 AMF Recovery Year 4 (d)	Program Year 6 AMF Recovery Year 5 (e)	Program Year 7 AMF Recovery Year 6 (f)	Program Year 8 AMF Recovery Year 7 (g)	Program Year 9 AMF Recovery Year 8 (h)	Program Year 10 AMF Recovery Year 9 (i)	Program Year 11 AMF Recovery Year 10 (j)
1 397 - Communication Equipment	In-Service Plant		$0	$0	$786,365	$0	$0	$0	$0	$0	$0	$0
2 Plant Capital Overheads	Input	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3 Capital Spend - Annual	Line 1 + Line 2		$0	$0	$786,365	$0	$0	$0	$0	$0	$0	$0
4 Capital Spend - Cumulative	PY Line 4 + CY Line 3		$0	$0	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365
5 COR - Annual	Input		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6 Cumulative COR	Line 5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7 Annual State Tax Depreciation			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8 Cumulative State Tax Depreciation	Line 7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9 Annual Federal Tax Depreciation	Pages 17 & 18, Line 42		$0	$0	$157,273	$251,637	$150,982	$90,589	$90,589	$45,295	$0	$0
10 Cumulative Federal Tax Depreciation	PY Line 10 + CY Line 9		$0	$0	$157,273	$408,910	$559,892	$650,481	$741,070	$786,365	$786,365	$786,365
11 Annual Book Depreciation/Amortization	Pages 11 & 12, Line 42	5.00%	$0	$0	$19,659	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318
12 Cumulative Book Depreciation	Line 11		$0	$0	$19,659	$58,977	$98,296	$137,614	$176,932	$216,250	$255,569	$294,887
13 Accumulated Deferred Income Tax (State)	(Line 12 - Line 8) x 0%	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14 Accumulated Deferred Income Tax (Federal)	(Line 12 - Line 10) x 21%	21.00%	$0	$0	$28,899	$73,486	$96,935	$107,702	$118,469	$119,724	$111,467	$103,210
15 Accumulated Deferred Income Tax	Line 13 + Line 14		$0	$0	$28,899	$73,486	$96,935	$107,702	$118,469	$119,724	$111,467	$103,210
Rate Base Calculation												
16 Plant In Service	Line 4		$0	$0	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365
17 Accumulated Reserve for Depreciation	Line 12		$0	$0	($19,659)	($58,977)	($98,296)	($137,614)	($176,932)	($216,250)	($255,569)	($294,887)
18 Accumulated COR	Line 6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19 Deferred Tax Reserve	Line 15		$0	$0	($28,899)	($73,486)	($96,935)	($107,702)	($118,469)	($119,724)	($111,467)	($103,210)
20 Year End Rate Base	Line 16 + Line 17 + Line 18 + Line 19		$0	$0	$737,807	$653,902	$591,134	$541,049	$490,964	$450,391	$419,329	$388,268
Revenue Requirement Calculation												
21 Average Rate Base	Average Line 20		$0	$0	$368,903	$695,854	$622,518	$566,092	$516,006	$470,677	$434,860	$403,798
22 Deferred Tax Proration Adjustment	Pages 23 & 24, Line 60		$0	$0	$1,240	$1,914	$1,007	$462	$462	$54	($354)	($354)
23 Average Rate Base adjusted	Line 21 + Line 22		$0	$0	$370,144	$697,768	$623,524	$566,554	$516,469	$470,731	$434,505	$403,444
24 Pre-Tax WACC	RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
25 Return and Taxes	Line 23 x Line 24		$0	$0	$30,463	$57,426	$51,316	$46,627	$42,505	$38,741	$35,760	$33,203
26 Book Depreciation	Line 11		$0	$0	$19,659	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318
27 Property Taxes	RIPUC Docket No. 5098 FY 2022 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing	2.87%	$0	$0	$0	$22,004	$20,876	$19,748	$18,619	$17,491	$16,362	$15,234
28 Annual Revenue Requirement	**Line 25 + Line 26 + Line 27**		**$0**	**$0**	**$50,122**	**$118,749**	**$111,510**	**$105,693**	**$100,443**	**$95,550**	**$91,440**	**$87,756**

CY Current Year
PY Prior Year

The Narragansett Electric Company
AMF Plan
Revenue Requirement - Electric Telecommunication Equipment (397)

Program Year 12	**Program Year 13**	**Program Year 14**	**Program Year 15**	**Program Year 16**	**Program Year 17**	**Program Year 18**	**Program Year 19**	**Program Year 20**	**Program Year 21**		
AMF Recovery Year 11	**AMF Recovery Year 12**	**AMF Recovery Year 13**	**AMF Recovery Year 14**	**AMF Recovery Year 15**	**AMF Recovery Year 16**	**AMF Recovery Year 17**	**AMF Recovery Year 18**	**AMF Recovery Year 19**	**AMF Recovery Year 20**		
(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365		
$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318		
$334,205	$373,523	$412,842	$452,160	$491,478	$530,796	$570,115	$609,433	$648,751	$688,069		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$94,954	$86,697	$78,440	$70,183	$61,926	$53,669	$45,413	$37,156	$28,899	$20,642		
$94,954	$86,697	$78,440	$70,183	$61,926	$53,669	$45,413	$37,156	$28,899	$20,642		
$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365	$786,365		
($334,205)	($373,523)	($412,842)	($452,160)	($491,478)	($530,796)	($570,115)	($609,433)	($648,751)	($688,069)		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
($94,954)	($86,697)	($78,440)	($70,183)	($61,926)	($53,669)	($45,413)	($37,156)	($28,899)	($20,642)		
$357,206	$326,145	$295,083	$264,022	$232,961	$201,899	$170,838	$139,776	$108,715	$77,654		
$372,737	$341,676	$310,614	$279,553	$248,491	$217,430	$186,369	$155,307	$124,246	$93,184		
($354)	($354)	($354)	($354)	($354)	($354)	($354)	($354)	($354)	($354)		
$372,383	$341,321	$310,260	$279,198	$248,137	$217,076	$186,014	$154,953	$123,891	$92,830		
8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%		
$30,647	$28,091	$25,534	$22,978	$20,422	$17,865	$15,309	$12,753	$10,196	$7,640		
$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318	$39,318		
$14,105	$12,977	$11,849	$10,720	$9,592	$8,463	$7,335	$6,206	$5,078	$3,950		
$84,071	**$80,386**	**$76,701**	**$73,016**	**$69,332**	**$65,647**	**$61,962**	**$58,277**	**$54,592**	**$50,908**	**$1,436,155**	**$0**

The Narragansett Electric Company
AMF Plan
Illustrative Revenue Requirement - Electric Software Equipment (303)

		Source		Program Year 1 & 2 AMF Recovery Year 1	Program Year 3 AMF Recovery Year 2	Program Year 4 AMF Recovery Year 3	Program Year 5 AMF Recovery Year 4	Program Year 6 AMF Recovery Year 5	Program Year 7 AMF Recovery Year 6	Program Year 8 AMF Recovery Year 7	Program Year 9 AMF Recovery Year 8	Program Year 10 AMF Recovery Year 9	Program Year 11 AMF Recovery Year 10
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	303 - Intangible	In-Service Plant		$483,368	$114,250	$0	$6,613,370	$0	$0	$0	$0	$0	$0
2	Plant Capital Overheads	Input	0%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Capital Spend - Annual	Line 1 + Line 2		$483,368	$114,250	$0	$6,613,370	$0	$0	$0	$0	$0	$0
4	Capital Spend - Cumulative	PY Line 4 + CY Line 3		$483,368	$597,618	$597,618	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988
5	303 - COR - Annual	Input											
6	Cumulative COR	Line 5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Annual State Tax Depreciation												
8	Cumulative State Tax Depreciation	Line 7		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	Annual Federal Tax Depreciation	Pages 19 & 20, Line 61		$80,553	$180,146	$199,186	$1,220,799	$2,223,287	$2,204,898	$1,102,118	$0	$0	$0
10	Cumulative Federal Tax Depreciation	PY Line 10 + CY Line 9		$80,553	$260,700	$459,886	$1,680,685	$3,903,973	$6,108,870	$7,210,988	$7,210,988	$7,210,988	$7,210,988
11	Annual Book Depreciation	Pages 13 & 14, Line 63	14.29%	$34,526	$77,213	$85,374	$557,757	$1,030,141	$1,030,141	$1,030,141	$995,615	$952,928	$944,767
12	Cumulative Book Depreciation	Line 11		$34,526	$111,740	$197,114	$754,871	$1,785,012	$2,815,153	$3,845,294	$4,840,908	$5,793,836	$6,738,603
13	Accumulated Deferred Income Tax (State)	(Line 12 - Line 8) x 0%	0.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Accumulated Deferred Income Tax (Federal)	(Line 12 - Line 10) x 21%	21.00%	$9,666	$31,282	$55,182	$194,421	$444,982	$691,681	$706,796	$497,717	$297,602	$99,201
15	Accumulated Deferred Income Tax	Line 13 + Line 14		$9,666	$31,282	$55,182	$194,421	$444,982	$691,681	$706,796	$497,717	$297,602	$99,201
	Rate Base Calculation												
16	Plant In Service	Line 4		$483,368	$597,618	$597,618	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988
17	Accumulated Reserve for Depreciation	Line 12		($34,526)	($111,740)	($197,114)	($754,871)	($1,785,012)	($2,815,153)	($3,845,294)	($4,840,908)	($5,793,836)	($6,738,603)
18	Accumulated COR	Line 6		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Deferred Tax Reserve (ADIT)	Line 15		($9,666)	($31,282)	($55,182)	($194,421)	($444,982)	($691,681)	($706,796)	($497,717)	($297,602)	($99,201)
20	Year End Rate Base	Line 16 + Line 17 + Line 18 + Line 19		$439,176	$454,597	$345,323	$6,261,696	$4,980,995	$3,704,155	$2,658,899	$1,872,363	$1,119,550	$373,185
	Revenue Requirement Calculation												
21	Average Rate Base	Average Line 20		$219,588	$227,299	$399,960	$3,303,509	$5,621,345	$4,342,575	$3,181,527	$2,265,631	$1,495,957	$746,367
22	Deferred Tax Proration Adjustment	Pages 25 & 26, Line 90				$1,026	$5,976	$10,755	$10,589	$649	($8,974)	($8,589)	($8,516)
23	Average Rate Base adjusted	Line 21 + Line 22		$219,588	$227,299	$400,986	$3,309,486	$5,632,100	$4,353,164	$3,182,176	$2,256,657	$1,487,367	$737,852
24	Pre-Tax WACC	RIPUC Docket No. 4770, Compliance Att 2, Schedule 1, Pg 4		8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%
25	Return and Taxes	Line 23 x Line 24		$18,072	$18,707	$33,001	$272,371	$463,522	$358,265	$261,893	$185,723	$122,410	$60,725
26	Book Depreciation	Line 11		$34,526	$77,213	$85,374	$557,757	$1,030,141	$1,030,141	$1,030,141	$995,615	$952,928	$944,767
27	Property Taxes	RIPUC Docket No. 5098 FY 2022 Electric Infrastructure, Safety,and Reliability Plan Reconciliation Filing	2.87%	$0	$0	$13,945	$11,494	$185,291	$155,726	$126,160	$96,595	$68,021	$40,672
28	**Annual Revenue Requirement**	**Line 25 + Line 26 + Line 27**		**$52,598**	**$95,920**	**$132,320**	**$841,623**	**$1,678,953**	**$1,544,132**	**$1,418,194**	**$1,277,933**	**$1,143,359**	**$1,046,164**

CY Current Year
PY Prior Year

The Narragansett Electric Company
AMF Plan
Revenue Requirement - Electric Software Equipment (303)

Program Year 12 AMF Recovery Year 11 (k)	Program Year 13 AMF Recovery Year 12 (l)	Program Year 14 AMF Recovery Year 13 (m)	Program Year 15 AMF Recovery Year 14 (n)	Program Year 16 AMF Recovery Year 15 (o)	Program Year 17 AMF Recovery Year 16 (p)	Program Year 18 AMF Recovery Year 17 (q)	Program Year 19 AMF Recovery Year 18 (r)	Program Year 20 AMF Recovery Year 19 (s)	Program Year 21 AMF Recovery Year 20 (t)		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*7,210,988*	
$0	$0	$0	$0	$0		$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988		
$472,385	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988	$7,210,988		
($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)	($7,210,988)		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)		
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$186,592	$0	$0	$0	$0	$0	$0	$0	$0	$0		
($4,258)	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$182,334	$0	$0	$0	$0	$0	$0	$0	$0	$0		
8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%	8.23%		
$15,006	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$472,385	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$13,557	$0	$0	$0	$0	$0	$0	$0	$0	$0		
$500,949	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$9,732,146**	**$0**

PUC 3-13

Cost Estimates, O&M Savings, and Revenue Requirement

Request:

Referring to Figure 11.15 in the Business Case (Bates page 155) showing the Avoided AMR Costs,

(a) please provide a schedule showing the timeframe (by year) over which these costs would have been incurred by the Company in the absence of AMF, including the costs that would have been incurred in each year.

(b) of the cost categories listed in Figure 11.5, please provide a schedule which shows the amount of these categories of costs already incurred (if any) by the Company from the date that the PPL acquisition was effective through the end of CY 2022, and a projection of these categories of costs that the Company forecasts still will be incurred by the Company until AMF is fully deployed.

Response:

Please see Attachment PUC 3-13. There are two tabs in the spreadsheet, labeled PUC 3-13a and PUC 3-13b.

Tab PUC 3-13a includes two different sets of data.

(a) The first set is the avoided AMR costs by year from the Confidential BCA Model provided in Attachment H that appear in Figure 11.15 in the Business Case, as requested in the question above, and

(b) A set of data including the AMR personnel reduction benefits by year.

Tab PUC 3-13b includes the Capital and O&M expenditures incurred by Rhode Island Energy from June-December 2022 for AMR Meter Capital and O&M expenditures and a forecast of budgeted AMR Meter Capital and O&M expenditures between now and when the AMF meters are fully deployed.

The values on Tab PUC 3-13b are not grouped into the same categories as the benefits shown on Tab PUC 3-13a. Rhode Island Energy is including the AMR personnel reduction benefits on Tab PUC 3-13a to provide a more "apples-to-apples" comparison between the AMF benefit calculations and the budgeted Capital and O&M expenditures.

Prepared by or under the supervision of: Wanda Reder and Flora Flygt

Attachment PUC 3-13

Please see the native (Excel) version of Attachment PUC 3-13.

PUC 3-14

Obsolescence of AMR Technology

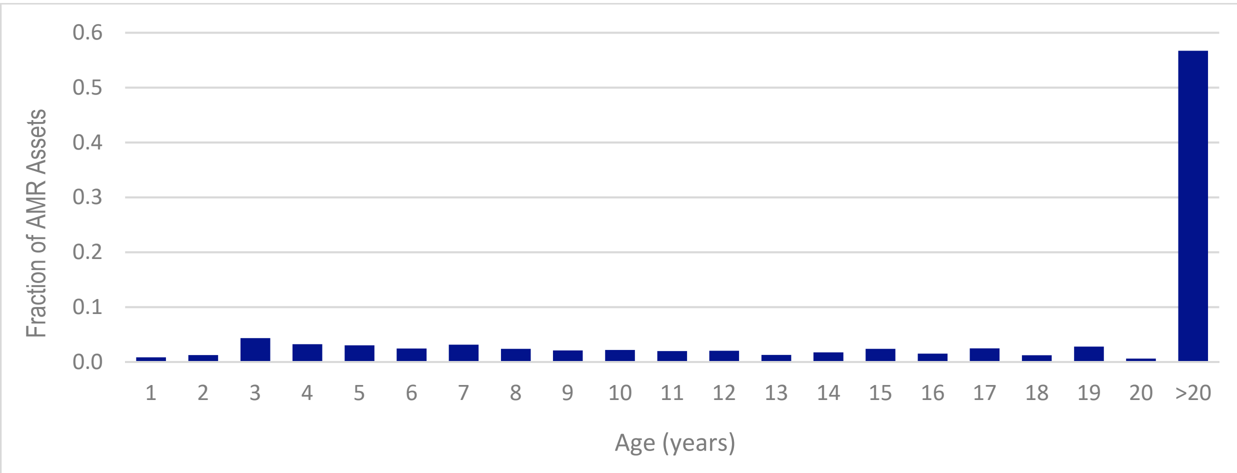
Request:

In several places in the testimony and the Business Case, the Company asserts that the current AMR metering technology is becoming obsolete and needs to be replaced (see, e.g., "Current electric meter fleet needs to be replaced because it is reaching the end of design life and is obsolete and will not scale;" Business Case, p. 5 of 200). Please provide the approximate timeframe and calendar year when the Company believes that the obsolescence of the AMR metering technology would make it impossible as a practical operational matter to continue using the AMR technology.

Response:

It is difficult to put a precise timeframe on when the current AMR metering technology will become obsolete such that it will be impossible as a practical operational matter for Rhode Island Energy to continue using AMR metering technology to operate the distribution system. That said, the risk of this level of obsolescence already exists and continues to increase with the passage of time. It is reasonable to expect that once AMR meters reache the end of their useful lives, the meter failure rate will accelerate. Using Rhode Island Energy meter data that was based upon information provided in May 2022, approximately 60 percent of the electric ERT and solid-state AMR assets that are currently in the field will reach the end of their estimated 20-year design life by the end of calendar year 2024. After that time, Rhode Island Energy expects that the meter failure rate will accelerate, along with Rhode Island Energy's need to replace the failed meters. Figure 2.4 in the AMF Business Case provides the age distribution of the electric AMR assets and is shown below (Bates 21-22):

Figure 2.4: Current age of electric AMR assets



At the same time, however, the Company already has observed that vendors have shifted their focus from prioritizing AMR meter needs to addressing the needs of the growing AMF market. The Company does not know exactly when vendors will stop supporting AMR technologies completely, but as more and more utilities adopt AMF meters that tipping point draws nearer. Although the Company could continue to operate the AMR system beyond the AMR metering technology's end of design life, doing so without vendor support will create multiple challenges. These challenges could include increasing needs for equipment replacements, difficulty in obtaining replacements, and more maintenance requirements.

The Company also believes the AMR metering technology will become impractical because it lacks the functionality and ability to meet the Company's business needs. The AMF Business Case describes the current needs and benefits for granular data and how the AMF platform can be built upon to address future opportunities. AMR is generally incapable of providing these capabilities and does not offer operators the visibility needed today and in the future to manage the system as complexity increases.

PUC 3-15

Obsolescence of AMR Technology

Request:

Please provide the approximate timeframe and calendar year when the Company believes that failing to replace the AMR meters with a new technology would become imprudent, defining "prudency" in the context of its meaning in utility ratemaking.

Response:

Please see the Company's response to PUC 3-14 for the approximate timeframe within which AMR meters are expected to reach the end of their useful life. As discussed in the response to PUC 3-14, it is not possible to identify a timeframe or calendar year by which the Company will no longer be able to operate the electric distribution system with AMR meters. It is also not possible to predict at which point these AMR meters will fail or when vendors will no longer provide support for the technology or replacement equipment, such that failing to replace the AMR meters would become imprudent; however, the Company has an ongoing legal obligation to address its aging electric AMR metering assets that are approaching the end of design life. Based on the Company's industry experience and discussions with its vendors, the support window for AMR is limited for the aged technology, and the meters will need to be replaced in the near term. For the reasons discussed below, it would be imprudent to continue to replace aging AMR meters with like-for-like AMR technology for any longer than is necessary to implement the infrastructure to adopt AMF meters.

The Company believes that replacing the AMR meters with AMF now is reasonably necessary and prudent for two reasons. First, the cost to deploy AMF is reasonable and fiscally sound. The BCA for AMF is strongly positive on its own, with and without the integration of grid modernization or the dependence on other systems. The AMF Business Case demonstrates substantial customer and system safety and reliability benefits that significantly exceed the projected costs (on a NPV and nominal basis). Also, as discussed in the Company's response to PUC 1-4, because the Company's cost-recovery proposal is based on historical actual costs, the Company only recovers costs it actually incurs, and the Commission will have an opportunity semi-annually to review the Company's spending against the overall project costs, thereby ensuring that customers only pay for costs that are reasonably and prudently incurred in accordance with the Plan as approved. Additionally, under the Company's proposal, customers will receive back 80% of the projected avoided O&M benefits regardless of when those benefits are achieved, which is embedded into the proposed revenue requirement in the AMF Business Case, making the AMF investment economical for customers.

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

Second, AMF is necessary for safety and reliability reasons. As discussed in the pre-filed direct testimony of Company Witness David Bonenberger and in the AMF Business Case, there are operational challenges occurring across the electric distribution system because of increased adoption of distributed energy resources, electric vehicle charging, electric heat pumps, and advanced "smart" technologies that enable customers to actively manage energy use in their homes and places of business. All these factors require greater operator visibility and situational awareness of electric grid system conditions that are becoming increasingly dynamic and complex. AMR meters do not provide the necessary functionality to operate, manage, and control the modern-day grid and effectively integrate customer-owned resources. AMF provides the operational visibility that is necessary to ensure continued safe and reliable service amidst the changing electric distribution system.

Delaying the AMF investment until either the AMR meters fail, or the technology is no longer supported or available in the marketplace creates operational risk, as discussed above, and may negate or delay the benefits, both financial and otherwise, that would be realized by proceeding with the investment today.

PUC 3-16

Grid Mod and AMF: Mandatory or Optional

Request:

Please reconcile (i) the Company's position that Grid Modernization is a "non-discretionary" component within the Electric ISR filing (Docket No. 22-53-EL) that is required by statute (Bates page 32 of the ISR filing), with (ii) the position in this case that the Company will choose not to go forward for financial reasons with AMF unless the Company obtains timely recovery of the full cost of AMF. In other words, how can Grid Modernization and AMF be respectively mandatory and optional at the same time, when AMF is foundational and integral to Grid Modernization (see Business Case, Section 4)?

Response:

The Company does not view either advanced metering functionality ("AMF") or the grid modernization investments as mandatory or optional, as framed in this request. Rather, the Company's position is that both are necessary investments to ensure that the Company can most effectively and efficiently maintain safe and reliable service as the electric distribution system continues to evolve and distributed energy resources ("DER") continue to proliferate. The Company, however, recognizes that, if the Public Utilities Commission ("PUC") does not agree and, therefore, does not approve its proposals, including for cost recovery, then it will need to pursue an alternative path. As described herein, the Company expects that the alternative pathways available will result in sub-optimal performance and increased expense overall.

As indicated in the Company's response to PUC 1-22, a non-discretionary capital investment is defined within the Infrastructure, Safety, and Reliability ("ISR") Provision, R.I.P.U.C. No. 2199, as a "capital investment related to the Company's commitment to meet statutory and/or regulatory obligations." The Company's proposed grid modernization investments reflect the Company's commitment to meeting the relevant statutory and regulatory obligations. (Please see the Company's response to PUC 1-23 for the relevant statutory and regulatory obligations.) If presented in the ISR, AMF would fall under the same classification. The Company's commitment to meeting statutory and regulatory obligations is unwavering; however, the approach is contingent upon regulatory directives and financial risk to the Company.
In this case, the Company's proposed grid modernization investments represent the most beneficial and cost-effective plan to satisfy the Company's legal obligations and further the Company's commitment to ensuring that the State can effectuate its statutory obligations pursuant to the 2021 Act on Climate and the 2022 amendments to the Renewable Energy Standard. If AMF is approved and instituted, the benefits of grid modernization would be enhanced, and the optimal functionality of the grid modernization investments would be realized.

Prepared by or under the supervision of: Wanda Reder, Kathy Castro, and Philip Walnock

An alternative approach that forgoes all or a portion of the proposed grid modernization investments or forgoes AMF would place the Company in a reactive position, which means the Company would need to implement other less cost-effective alternatives in piecemeal to address the changes occurring on the electric distribution system This would likely result in higher costs to customers over the long term and be an impediment to the efficient interconnection of DER.

(This response is identical to the Company's response to PUC 1-25 in the Electric ISR Docket No. 22-53-EL.)

Prepared by or under the supervision of: Wanda Reder, Kathy Castro, and Philip Walnock

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PUC 3-17

The Proposed Advanced Metering Functionality Provision

Request:

Referring to the proposed Advanced Metering Functionality Provision,

(a) the definition of the "AMF Revenue Requirement" uses the term "AMF-related plant-in-service". Please provide a comprehensive list of all the categories of investments that the Company anticipates will be made which will fall within the category of "AMF-related plant-in-service," and, thus, will be eligible for cost recovery under the proposed tariff.

(b) the definition of "Recoverable O&M Expense" identifies "incremental O&M expense that is incurred by the Company as a result of implementing AMF." Please provide a comprehensive list of all the categories of O&M expenses that the Company anticipates will be incurred which will fall within the category of "incremental O&M expense that is incurred by the Company as a result of implementing AMF," and, thus, will be eligible for cost recovery under the proposed tariff.

Response:

(a) The Company anticipates that the capital AMF-related plant in service will fall into three capital categories for cost recovery under the proposed tariff: 1) Meters, 2) Intangible Software, and 3) Network/Communication Equipment. Please see the responses to PUC 1-11, PUC 1-12, and PUC 1-13, specifically Attachment PUC 1-11, Attachment PUC 1-12, and Attachment PUC 1-13, for the detailed listings of anticipated capital investments which would fall into these categories. For purposes of developing an illustrative revenue requirement in this filing, the Company assumed the investments listed on the referenced attachments would fall into the above cost categories. However, when the actual cost recovery filings are made, the Company will calculate the amounts for cost recovery based on the actual capital cost categories (FERC accounts) in which the investments are recorded on the Company's books.

(b) Please see Attachment PUC 3-17 for a comprehensive list of the anticipated AMF related O&M costs that the Company expects to incur and be eligible for cost recovery under the proposed tariff.

Prepared by or under the supervision of: Stephanie A. Briggs and Bethany L. Johnson

The Narragansett Electric Company
d/b/a Rhode Island Energy
O&M Costs Categories

Cost Category_1	Cost Category_3	Cost Category_4	Full Description
01.Meter	Ancillary Equipment	Safety Equipment	Ancillary Devices
01.Meter	Meter Base	Meter Bases	Total Meter Base Repairs (Electric Meter Base Repairs)
02.Network	PPL Labor	AMF RF Network	RF Network Operations - PPL Internal Labor
02.Network	Vendor /External Labor	RF Network Ops MSP	RF Network Operations & Maintenance - MSP
02.Network	Gateway	Backhaul	Gateway Telecomm Backhaul
03.Systems	PPL Labor	AMO	AMO Headend & MDMS Operations - PPL Internal Labor
03.Systems	Operations	NMA/AGA	Network Model Analytics / AGA - SaaS
03.Systems	Operations	Data Lake	Analytics RTB Cost
03.Systems	Operations	Data Lake	Data Lake & Analytics (Storage, Processing, Visualization, Software License, VMs) OpEx cost
03.Systems	Operations	CSS	CSS Enhancements RTB Cost
03.Systems	Annual License (SaaS) - Headend	Headend	Annual License (SaaS) - Headend
03.Systems	Operations	Headend	AMF Headend RTB Cost
03.Systems	WiSun	WiSun	AMF WiSun RTB Cost
03.Systems	Annual License (SaaS) - WiSun	WiSun	Annual License (SaaS) & Support - WiSun
03.Systems	Annual License (SaaS) - MDMS	MDMS	Annual License (SaaS) - MDMS
03.Systems	MDMS	MDMS	AMF MDMS RTB Cost
03.Systems	Operations	Middleware	Middleware RTB Cost (Labor)
03.Systems	Operations	Middleware	Middleware RTB Cost (Non-Labor/MS Azure On-Going Middleware)
03.Systems	Operations	Cybersecurity	On-Going CyberSecurity Updates and Best Practice System Buildation
03.Systems	Operations	Customer Portal	Customer Portal RTB Cost (Labor)
03.Systems	Operations	Customer Portal	Customer Portal RTB - (Non-Labor) Site Core Content Management
03.Systems	Operations	Customer Portal	Customer Portal RTB - (Non-Labor) MS Azure Website Cloud Costs
03.Systems	Operations	Customer Alerting	Customer Portal RTB - (Non-Labor) Twilio (SendGrid)
03.Systems	Operations	Time Varying Rates (TVR)	Time Varying Rates (TVR) Operations
03.Systems	Operations	ADMS & OMS	OMS Integration RTB (Labor) - ADMS
03.Systems	Operations	ADMS & OMS	OMS Integration RTB (Labor) - OMS
03.Systems	Operations	ADMS & OMS	OMS Integration RTB (Non-Labor) - ADMS GE Eterra
03.Systems	Operations	ADMS & OMS	OMS Integration RTB (Non-Labor) - OMS GE PowerOn
03.Systems	Operations	Grid Edge & Load Dissag.	Grid Edge Computing & Load Disaggregation (System Cost)
04.Program	PPL Labor	PPL Labor	Internal PPL Labor - Change Management
04.Program	Vendor /External Labor	Change Management Vendor Labor	PMO Vendor - Change Management - Business Integration Lead (Opex)
04.Program	Vendor /External Labor	Change Management Vendor Labor	PMO Vendor - Change Management - Analyst(s) (Opex)
04.Program	Materials / Content / Training	Materials	Change Management - External Customer Facing Communications (Electric Deployment Phase)
04.Program	Materials / Content / Training	Training	Change Management - Training (Electric Deployment Phase)
04.Program	Materials / Content / Training	Training	Communications Network Equipment and Installation (Training)

PUC 3-19

Relationship to Climate Mandates and Managing DER

Request:

Please compare (1) the assertion in the testimony of Walnock & Reder, p. 26 of 84, stating:

> "In short, AMR technology cannot retrieve metering data frequently enough to provide the visibility to operate the electric distribution system safely and reliably in a future that includes the level of DER integration necessary to achieve the State's Climate Mandates"

with

(2) the description of the "DER/Monitor/Manage" activity in the current Electric ISR Docket No. 22-53-EL, in which Ms. Reder is a panel witness listed on pre-filed testimony, stating:

> "DER/Monitor/Manage enables visibility of DERs and the ability to manage them. This management ranges from ramping operations to full curtailment of an individual DER output if needed, for distribution safety or reliability purposes." (p. 32 of 39)

(a) Which technology or activity is providing the visibility to manage the DER: the AMF, the DER/Monitor/Manage, or both working together? Please explain. To the extent the answer is that the visibility is provided by both working together, please explain the level of visibility provided by each.

(b) Is there a proposal to invest or incur costs to be recovered in rates from the DER/Monitor/Manage activity in either the proposed Advanced Metering Functionality Provision, an Electric ISR filing, or the next distribution rate case? If so, please identify the costs and timing, including distinguishing between O&M and capex.

(c) If both AMF and the DER/Monitor/Manage activity are needed to work together to achieve the needed visibility, are any of the costs associated with DER/Monitor/Manage included in the BCA? If so, please quantify. If not, please explain why not.

Prepared by or under the supervision of: Wanda Reder

Response:

(a) Both AMF and DER Monitor/Manage provide added visibility for DER operations. AMF provides visibility at the point where the customer connects to the Company where bi-directional metering capability measures energy used, and excess energy produced. Granular and timely customer load data from AMF meters supports more accurate load-flow calculations, enabling better system power flow and voltage profile system visibility where actions can be initiated through the ADMS/DERMs software platform to mitigate violations and to optimize operations. Types of information that could be available for DER integration from AMF are load profiles, peak-demand, hosting capacity, beneficial DER locations, interconnection queue, and voltage / thermal limits. DER Monitor/Manage provides the added ability to visualize and manage DER at the inverter, located behind the meter, where direct current is being converted to alternating current for customer use or for export. DER Monitor/Manage provides an opportunity to more fully integrate DER with the distribution system by providing functionality such as increasing hosting capacity, reducing curtailments, and assisting in balancing load and generation through the ADMS/DERMS software platform. For additional information on DER Monitor/ Manage, see Attachment G in the Grid Modernization Plan that was filed by the Company on December 30, 2022, and which has been filed in this docket as Attachment DIV 1-36-5.

There is a proposal to pursue DER Monitor/Manage in the Grid Modernization Plan and the associated Electric ISR filing The O&M and capex costs and timing are summarized below as reflected in Section 6 (Figure 6.4 – Bates page 129) and 8 (Figure 8.21- Bates page 194) of the Grid Modernization Plan. DER Monitor/Manage functionality also assumes any additional approvals necessary to implement it and the availability of ADMS/DERMS.

Program Category	FY23	FY24	2025	2026	2027	2028	Total
Total DER Monitor Manage Cash Flow	$ -	$ -	$ -	$ 2,288,076	$ 4,043,598	$ 4,414,290	**$ 10,745,964**

Program Category	Project Costs (000's)				Future Project Costs	Operating Costs		Total All BCA Costs (Nominal)	Total All BCA Costs (NPV)
	Install	Remove	OPEX	Total		RTB OPEX	RTB Telecom		
Total DER Monitor Manage	$ 10.7	$ -	$ -	$ 10.7	$ 103.3	$ 14.0	$ -	$ 128.0	$ 57.8

(b) Yes, AMF and DER Monitor/Manage work together to achieve the needed visibility. The Company did not include costs or benefits of DER Monitor / Manage in the AMF BCA because DER Monitor/Manage is not being proposed as part of the AMF Business Case. As more fully explained in the GMP, DER Monitor/Manage is a strategically important GMP functionality because it enables the visibility of DER and the ability to fully integrate DER into the electric distribution system. Accordingly, the costs and benefits of DER Monitor/Manage were included in the GMP.

(This response is identical to the Company's response to PUC 1-26 in the Electric ISR Docket No. 22-53-EL.)

Prepared by or under the supervision of: Wanda Reder

PUC 3-20

TSA Exit and Transition Costs

Request:

Referring to the testimony of Walnock & Reder, p. 47-48 (beginning at line 18), the witnesses state: "Before the TSA Exit, capability is needed to: (i) support the deployment of the Rhode Island Energy communication network, (ii) coordinate with the Customer Service System (CSS) transition while supporting AMR and billing, and (iii) develop functionality defined in Groups 1 and 2. These IT developmental efforts will occur in parallel with the TSA work; however, they are separate and apart from scope defined within the TSA."

(a) How does the Company define the "TSA Exit?"

(b) What is the date of the "TSA Exit?"

(c) Please describe the referenced scope of IT TSA work which is separate from the AMF development work. Please provide relevant references to the TSA to the extent it relates to the agreement.

(d) Are the individuals performing the IT TSA work (i) employees of National Grid, (ii) employees of the Company or PPL affiliates, (iii) contractors/vendors hired by National Grid, and/or (iv) contractors/vendors hired by the Company or PPL affiliates? Please describe.

(e) Is there overlap in the personnel providing services under the IT TSA and the AMF development work? If so, please describe and indicate whether these personnel are tracking their hourly time by type of work or whether the cost associated with their time is simply allocated between IT TSA and AMF development?

(f) Is the Company tracking separately the IT TSA work from the IT work that is occurring in parallel, such that the Commission can be confident that IT costs applicable to the TSA are not being recovered as costs related to the AMF project? Please explain.

Response:

a) In connection with PPL Rhode Island Holdings, LLC's acquisition of 100 percent of the outstanding common stock of The Narragansett Electric Company (the

"Acquisition:"), the Company entered into a Transition Service Agreement ("TSA") by and among National Grid USA Service Company, Inc. ('National Grid Service Company") and National Grid USA (solely with respect to Section 4.6) and the Company. Under the TSA, National Grid Service Company has an obligation to maintain its back-office systems to provide service to the Company's customers while the Company transitions to PPL Corporation's ("PPL") systems. The Company defines the term TSA Exit as the date on which the transition of operation of the Company entirely to PPL is complete and National Grid Service Company is no longer providing any services under the TSA.

b) Each individual service being provided under the TSA has a specific target date for conclusion, and each of them can terminate as soon as they are no longer needed. The initial term of the TSA is two years from the Acquisition close date, which sets a termination date of May 25, 2024. The TSA provides the option to extend that time period if necessary, but the Company currently expects that TSA Exit, as defined in the response to part (a), will occur no later than May 25, 2024.

c) The referenced testimony and scope of IT TSA work is the replacement of the following systems/functions from National Grid Service Company with Company systems that provide like or similar functionality.

1. Meter reading for residential/commercial customers – This is a drive-by and walk-by meter reading system for both gas and electric meters. The system collects a single monthly meter reading for the monthly customer bill.

2. Meter reading for large commercial/industrial Customers – This is two remote meter reading systems, one for electric and one for gas meters. The systems read interval usage for each 15 minute period in the day on a daily basis.

3. Interval meter data database supporting customer billing, customer web presentment, and retail settlement.

4. Retail settlement for electric customers – This is settlement of customer electric usage with electric suppliers and ISO NE.

5. Load Profiling – This application is used to build a load profile for each customer rate class. A load profile shows typical customer

electric consumption for each hour of each day. Load profiles support retail settlement and other utility load analysis functions.

6. Wholesale electric settlement – This includes meter readings for each hour where electricity flows between RIE and another electric utility or electric generator and then gets reported to ISO NE.

7. Meter asset management and meter testing – This application holds meter inventory for all gas and electric meters including those in inventory as well as those installed at customer premises. This includes specialized meter test equipment to conduct meter testing to ensure meter read accuracy and meet regulatory requirements.

d) Employees of National Grid Service Company are involved in providing system details, data, and joint planning. Employees of the Company are involved in planning, designing, implementing, testing, and cutting over to the new systems. The Company generally does not know if individuals representing National Grid Service Company in joint planning activities are employees, contractors, or vendors. Contractors/vendors hired by the Company are involved in planning, designing, implementing, testing, and cutting over to new systems.

e) There is overlap in the Company personnel working on IT TSA and AMF. Separate accounting codes are used to charge individual time spent working on these activities.

The system integration vendor has assigned costs to these separate accounting codes in advance based on requirements and estimates, and these will be revised if/as circumstances change.

For software product vendors, the overlap is with the vendor providing the interval meter database, customer billing determinants, and retail settlement functions for IT TSA, as well as meter reading, and interfaces for AMF. Here the costs have been allocated between IT TSA and AMF based on the work components.

Interface teams include the customer and outage system teams, which have leaders, employees, contractors, and vendors. Here, the AMF items occurring in the IT TSA time period are related to customer billing and presentment, as well as automatic outage detection and remote connect/disconnect functionality. There is a mix of individuals tracking their time and allocation of time based on estimates.

f) The Company designed a methodical cost-tracking approach to differentiate IT TSA Exit development work from IT work for the AMF project that is occurring in parallel. Specific sets of projects are used for the TSA work and other sets are used for the AMF project. Individuals are trained as to what projects should be charged for what type of work. Projects are closely monitored to ensure the accuracy of charges. The work is easily separated from a tracking perspective, as the TSA Exit will result in the implementation of the scope referenced in part (c) of this response, and the AMF work will result in the implementation of the functionality described in the AMF Business Case.

PUC 3-21

TSA Exit and Transition Costs

Request:

Referring to the "AMF vs. TSA Exit Cost Accounting" description found in Attachment H, page 37 of 38, are the investments, work and activities related to the MDMS the only investments, work, or activities that create overlap between TSA Exit cost incurrence and cost incurrence associated with the AMF deployment? If yes, please explain why this is the case. If not, please identify the other investments, work, or activities where such overlap in cost incurrence occurs.

Response:

Yes, MDMS is the only solution that has a direct overlap; the other applications are either all TSA Exit or AMF. Costs identified in Attachment H are Rhode Island Energy Electric only AMF costs and do not include any TSA Exit costs. A system is needed to store and process meter read data from a combination of both AMR and AMF meters during the deployment of AMF meters. In addition to this core functionality, the MDMS will also provide the ability to support the retail settlement process for both AMR and AMF meters. Having a single MDMS for these purposes is the most efficient way to process usage data during this timeframe when both AMR and AMF meters are being read. Also, deploying a single MDMS ensures that billing data will all be coming from the same system.

PUC 3-22

TSA Exit and Transition Costs

Request:

Referring to the "AMF vs. TSA Exit Cost Accounting" description found in Attachment H, page 37 of 38,

(a) Please provide a schedule which shows the estimated total cost of the "MDMS Implementation" by year and the estimated total cost of the "MDMS Ongoing/Annual SaaS cost" by year, to which the proposed allocations would apply.

(b) Please explain how the Company determined the referenced allocation percentages, including a schedule showing the calculations with appropriate references to sources of data.

(c) For the "MDMS Ongoing/Annual SaaS cost allocations," please indicate whether there is an allocation of these costs as "transition costs" relating to the ongoing costs of AMR prior to full deployment of AMF. If yes, please estimate and distinguish (i) costs up to the TSA Exit from (ii) costs incurred up to the date of full deployment of AMF when AMR is no longer used. If not allocated, please explain why not.

Response:

a) Please see Confidential Attachment PUC 3-22-1.

b) Please see Attachment PUC 3-22-2.

MDMS Implementation

The MDMS Implementation estimates of 36 percent (AMR), 20 percent (Settlement), and 44 percent (AMF) were determined based on the detailed requirements list for the MDMS platform.

There are a total of 224 functional requirements for the MDMS. Each of these have been tagged by functionality. 80 (35.7 percent) of the 224 are considered foundational MDMS bill read requirements, which the Company considers part of TSA Exit. 45 (20.09 percent) of the 224 are specific to retail settlement requirements in the MDMS, which the

Company considers part of TSA exit. 99 (44.20 percent) of the 224 are the AMF MDMS specific requirements. The Company used these percentages to break out the MDMS implementation costs and the AMF BCA Electric Only has the AMF MDMS portion.

<u>MDMS Ongoing/Annual SaaS</u>

For the MDMS Ongoing/Annual SaaS fees estimate, the Company used its internal cost allocation manual ("CAM") to develop the breakdown of the SaaS fee. The CAM is based on endpoints.

The Company carried through the retail settlement requirements and aligned with the ongoing percentage of functionality at 20 percent. The 80 percent was split between gas and electric endpoints.

Gas endpoints represent approximately 35 percent of the current active endpoints, while the electric endpoints represent the 65 percent balance. The AMR Gas 28 percent of ongoing functionality was calculated by taking 35 percent of 80 percent. The AMF Electric 52 percent was estimated by taking 65 percent of 80 percent. The Company applied 52 percent to the MDMS Ongoing/Annual SaaS fee, and the Company used this result within the Rhode Island Energy AMF BCA.

c) The "MDMS Ongoing/Annual SaaS cost allocations" within Attachment H are Rhode Island Energy Electric only AMF costs and do not include any TSA Exit costs (i.e., transition costs). The purpose of AMF vs. TSA Exit Cost Accounting is to illustrate how the Rhode Island Energy cost accounting was being kept separate and how costs would be charged.

Attachments PUC 3-22-1 to PUC 3-22-2

Please see the native (Excel) versions of Confidential Attachment PUC 3-22-1 and Attachment PUC 3-22-2.

PUC 3-23

Customer Service System (CSS)

Request:

Referring to the testimony of Walnock & Reder, p. 47 (lines 20-21), please describe more completely the work of "coordinating with the Customer Service System (CSS) transition while supporting AMR and billing?"

Response:

This refers to the addition of new AMF meter capabilities while simultaneously supporting the needs for legacy meters and customer billing and the transitioning of metering and customer billing from National Grid USA Service Company, Inc. while adding similar capabilities for the new AMF meters. This work will be done in parallel, but will be clearly identifiable as separate processes and therefore, leading to efficiency gains from performing at the same time. The work includes processes to support timely and accurate customer billing, meter readings, bill calculation, printing and mailing of customer bills, customer call center, all including data exchanges with electric retail suppliers and ISO-NE throughout the process.

PUC 3-24

Customer Service System (CSS)

Request:

Referring to the AMF Project Timeline on Bates page 71 and Section 5.5 of the Business Case (Bates page 63 of Book 2),

(a) Will the Rhode Island Energy CSS and back-office systems being developed for AMF also be designed to support AMR and billing by the Company after the TSA Exit to ensure continuous operations for the residual electric AMR metering operations until full AMF deployment is completed at the end of 2025? Please explain.

(b) Is the Company distinguishing (i) the base costs of developing a CSS and back-office systems which would have been incurred in the ordinary course of the acquisition and transition if AMF was not being proposed from (ii) incremental costs incurred to enable the CSS and back-office systems to function with AMF? Please explain.

(c) Please identify (i) the total cost of the CSS and back-office systems, (ii) an estimate of the base cost of the CSS and back-office systems which would have been incurred in the ordinary course of the acquisition and transition if AMF was not being proposed, and (iii) the incremental cost related to enabling the CSS and back-office systems to function with AMF.

(d) Please provide a schedule which describes each and all of the functionalities of the Rhode Island Energy CSS (including both AMF-related functionality and functionality necessary for the business-as-usual operation of the CSS). Please distinguish those functionalities that will be designed exclusively to support AMF from those functionalities that will be needed for operating the electric and gas businesses with or without AMF.

Response:

a) Yes, as part of TSA Exit work, the CSS and back-office systems will be configured to support existing AMR metering operations to ensure continuous operations for all Rhode Island Energy customers. AMF will incrementally develop functionalities within those systems without eliminating the support of non-AMF metering operations.

b) Yes, the Company is distinguishing between the base costs of developing a CSS and back-office systems from the costs to enable AMF. The costs described in Attachment H of Schedule PJW/WR-1 are specific to AMF and do not include the base costs of transitioning operations as part of the acquisition.

c)
- (i) The total cost of the CSS and back-office systems is approximately $72.8 million, which is the total of subparts (ii) and (iii).
- (ii) The base cost of the CSS and back-office systems is approximately $70.1 million, comprising $55.5 million for Rhode Island CIS/Billing and $14.6 million for Rhode Island Customer Service Applications.
- (iii) The incremental cost to enable the CSS and back-office systems to function with AMF is approximately $2.7 million. The new AMF integrations and coding between CSS and the MDMS consist of $1.7 million for coding and integrations estimated based on leveraging existing PPL Electric Utilities Corporation knowledge, processes, and code and includes planning, design, coding, modifications, testing, and implementation in years 1-4; and $1.0 million for the ongoing maintenance of the new AMF integrations.

d) CSS for Rhode Island Energy includes functionalities for receiving metering bill determinants and calculations of a bill, as well as many other functionalities, including processing customer payments, call desk communication with customers, requesting field meter work for new customers and change meter orders, bill payment arrangements, budget billing, data exchanges to electric suppliers for customers receiving supply from third party suppliers, and many more meter-related functionalities. The nineteen functionalities of the Rhode Island Energy CSS are as follows:

- i. Customer Account Management
- ii. Premise and Service Point
- iii. Products and Programs
- iv. Sales and Marketing
- v. New Construction
- vi. Start/Transfer Service
- vii. Gather Usage/Read Meters
- viii. Rates
- ix. Billing
- x. Bill Print

xi. Financial Accounting/General Ledger Closing
xii. Payments
xiii. Credit Management
xiv. Inbound/Outbound Communications
xv. Outages/Leaks
xvi. Energy Efficiency/Demand Response
xvii. Device Management/Testing
xviii. Field Investigation
xix. Stop Service

These nineteen functionalities need to be delivered with or without AMF.

PUC 3-25

MDMS

Request:

Referring to Section 5.4 of the Business Case (Bates page 62),

(a) If the Commission does not approve the AMF proposal, would the Company still need to develop a Meter Data Management System (MDMS)? If not, please explain why.

(b) Please provide a schedule which breaks down the functionalities of the Rhode Island MDMS and the estimated costs for designing and building each functionality. Please distinguish those functionalities that will be designed exclusively to support AMF from those functionalities that will be needed for operating the electric and gas businesses with or without AMF.

(c) If it is possible to reasonably estimate, please provide the estimated costs for designing and building each functionality. If not possible, please explain why.

(d) If the Commission were to decline to approve the AMF proposal, what is the Company's estimate of what the total cost of the MDMS implementation would be compared to the total cost of the MDMS implementation with AMF?

Response:

a) Yes, if the Commission does not approve the AMF proposal, the Company would still need to develop a Meter Data Management System ("MDMS"). Meter usage data collected through the existing meter reading business processes requires a system where it can be stored, processed, and delivered to downstream systems for the purpose of supporting processes like billing, settlement, load forecasting, and load profiling. The MDMS implementation proposed serves this function both for the existing meters as well as for AMF meters, and the functionality delivered can be scaled accordingly to support either.

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b) Please see the response to PUC 3-22, including Confidential Attachment PUC 3-22-1 and Attachment PUC 3-22-2 for a description of the functional requirements for the MDMS, including an identification of those designed exclusively to support AMF and those that will be needed for operating the electric and gas businesses with or without AMF. Although the Company does not have estimated costs for the development of each functionality, please see the response to PUC 3-22 for a detailed description of how the MDMS costs were allocated between AMF costs and non-AMF costs.

c) Please see the response to PUC 3-22, including Confidential Attachment PUC 3-22-1 and Attachment PUC 3-22-2 and the response to part (b), above. Estimated costs for designing and building each functionality are not available because the development of the MDMS is not performed on a building block basis per functional requirement. As described in the Company's response to PUC 3-22, the Company has taken diligent steps to appropriately allocate the costs between those necessary only for AMF, and those that will be necessary even in the absence of AMF.

d) The Company estimates that it will cost $5.66 million to implement Non-AMF MDMS. Please see the response to PUC 3-22, including Confidential Attachment PUC 3-22-1 and Attachment PUC 3-22-2 for additional explanation of this cost estimate.

PUC 3-26

AMF Backhaul Communications Technology

Request:

In the current Electric ISR Docket No. 22-53-EL, Attachment 3 on Bates page 115 indicates investment in a fiber network to be $19.4 million over a 21-month period spanning CY 2023 and CY 2024 and more than $60 million over a 5-year period through CY 2027. In addition, the following statement appears in the pre-filed testimony (Bates page 46):

> "Q. What are the fiber investments?
>
> A. Fiber investments are proposed to replace leased cellular services with a private fiber cabling network to support communication to substation relays and to back-haul data from other installed grid modernization investments and AMF smart meters. This technology is needed to accommodate the vast quantity of operational data required for GMP and AMF. The network will provide security, speed, and bandwidth to achieve the required functionality and to achieve cost-effective benefits." (emphasis added)

(a) If the fiber is "needed to accommodate" the back haul of AMF data, are the referenced fiber investments necessary to achieve any of the benefits included in the BCA for the AMF Business Case at the levels assumed in the BCA? If so, please identify and quantify the amount of the benefits in the BCA that cannot be achieved through AMF without the fiber investments.

(b) Is there an allocation of the cost of the fiber investment to AMF in the BCA? If yes, please quantify. If not, and the assertion in the ISR filing is accurate that the fiber technology is "needed" to accommodate the vast quantity of operational data required for GMP and AMF, please explain why such an allocation (allocated between AMF and other GMP functions) should not be considered as a cost of the AMF project in the BCA.

Response:

(a) The referenced fiber investments are not necessary to achieve the benefits included in the BCA for the AMF Business Case at the levels assumed in the BCA. The benefits can be achieved by the leased cellular costs that have been included for the backhaul.

(b) No. There is not an allocation of the cost of the fiber investment to AMF in the BCA. The private fiber backhaul solution that is included in the Foundational Investments in the GMP is primarily for operations to satisfy real-time SCADA and system protection needs. If that is approved, there could be an opportunity in the future to replace some of the AMF cellular backhaul and the associated on-going costs, where available and feasible. The fiber was not included in the AMF BCA because the cellular backhaul is assumed to provide the functionality in the BCA for the project duration.

(This response is identical to the Company's response to PUC 1-27 in the Electric ISR Docket No. 22-53-EL.)

PUC 3-27

AMF Backhaul Communications Technology

Request:

In the current Electric ISR Docket No. 22-53-EL, the filing contains the following description on Bates page 95:

> "Fiber – This project proposes to replace leased cellular services with a private fiber cabling network to support communication to substation relays and to back-haul GMP and AMF data. Leased cellular service has limited bandwidth and is subject to greater interference, especially during emergencies when communication is imperative. The 21- month planned spend is roughly 32% of the Distribution Fiber 5-year GMP plan." (emphasis added)

In contrast, in the AMF Business Case at Bates page 84, it discusses a back-hauling communication solution involving a "mesh-to-cellular" network, stating on Bates page 147:

> "This is the most common AMF architecture, particularly for large IOUs, and is proposed as the Company's AMF strategy. In this model, meters communicate wirelessly with each other, creating a "mesh" that connects to field-deployed (pole-mounted) collectors that transmit bulk meter data to the utility's back-office over a cellular backhaul. Under Rhode Island Energy's proposed architecture, cellular backhaul would be leased from established network providers such as Verizon and AT&T. However, Rhode Island Energy may consider moving towards a Company-owned private network for backhaul as a part of future operational telecommunications processes." (emphasis added)

This language quoted above appears to be taken nearly verbatim from the National Grid filing in Docket No. 5133. (See Bates page 147 of the National Grid Business Case)

(a) Please clarify and explain whether the Company intends to use (i) a mesh-to-cellular backhaul, (ii) the private fiber as referenced in the ISR filing quoted above, or (iii) some combination of both for AMF back-haul communications.

(b) If the Company intends to use private fiber for backhaul, as indicated in the Electric ISR filing, why did the Company not include the private fiber network as a component for the AMF deployment in the AMF case, instead of representing that "mesh-to-cellular" was the Company's proposed backhaul strategy?

Response:

(a) For the AMF deployment, the Company intends to use a mesh-to-cellular backhaul, and it was included in the BCA for the AMF Business Case. Backhaul capability is needed as the AMF system is deployed starting as soon as 2024. There is a private fiber backhaul in the fiscal year ("FY") 2024 Electric Infrastructure, Safety and Reliability Plan ("FY 2024 Electric ISR Plan") assumed to be deployed throughout the years to substations completing at the end of 2028.
If that fiber investment is approved in the FY 2024 Electric ISR Plan and moves forward as scheduled for real-time operational needs, the cellular backhaul for AMF collectors and gateways that are substation based, could be replaced with fiber if it is feasible and as it becomes available. Cellular backhaul would continue for collectors and gateways that are not located in a substation. As described in the response to part b) below, the cost of the private fiber investment was included in the GMP Business Case; it was not included in the AMF Business Case.

(b) Mesh to cellular backhaul was assumed in the AMF Business Case because it will meet the project schedule requirements and there is certainty that it will be available when and where needed. Due to certainty of cellular backhaul availability and its capability to deliver the BCA benefits, it was assumed as the only backhaul in the AMF BCA throughout the entire analysis period. Grid operational needs are the main driver for the fiber backhaul. Please also see the Company's response to PUC 1-27 for additional explanation of the potential future benefits of fiber backhaul, and, to the extent that it becomes available where needed for AMF backhaul purposes, it may be utilized in the future, though difficult to quantify. For this reason, the fiber backhaul cost and benefits were included in the GMP; there are no fiber allocations for backhaul to the AMF BCA.

(This response is identical to the Company's response to PUC 1-28 in the Electric ISR Docket No. 22-53-EL.)

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PUC 3-28

AMF Backhaul Communications Technology

Request:

In a section of the Business Case which mirrors the same section in the National Grid filing, the Rhode Island Energy text repeats most of the language from the National Grid filing, except that Rhode Island Energy dropped out the following sentence: "Any potential savings to FAN infrastructure in using mesh-to-fiber collectors is offset by the additional cost to deploy private fiber." Please explain why this sentence was apparently deleted by Rhode Island Energy. (Compare Rhode Island Energy's Business Case at Bates page 85 to the National Grid Business Case at Bates pages 148-149).

Response:

Rhode Island Energy did not have the background analysis or the detailed communication architecture plan upon which National Grid based its analysis for this statement; therefore, Rhode Island Energy did not include it in its AMF Business Case.

PUC 3-29

AMF Backhaul Communications Technology

Request:

Does Rhode Island Energy's BCA assume use of the cellular solution or the private fiber solution, or some combination of both? Please provide the total cost that was assumed in the BCA for backhauling the AMF data and identify where the cost information can be found in the BCA model.

Response:

Rhode Island Energy's BCA assumes a privately owned RF mesh network is built to communicate with AMF meters. The backhaul of the meter data to and from the Headend system and gateways is assumed to use a cellular solution in the BCA. The total costs that were assumed in the BCA for cellular backhauling were $3,578,978 ($2022) for the entire 20-year period. The cost information is included in the BCA model in Tab "10-RI AMF COST MODEL," row 46, cell O46.

PUC 3-30

Electric Meter Count

Request:

Please provide the total number and net book value of electric meters in service as of the end of CY 2022 (or as of the most recent date that such information is readily available) which the Company will replace with smart meters by the AMF full deployment date. Please also break down this information by rate class. To the extent that the Company records the capitalized meter installation cost separately, please include the installation cost in the totals, and also show the bare cost and installation costs separately.

Response:

As of January 18, 2023, the total number of meters in service is 532,174. As of December 31, 2022, the net book value of all the electric meters was $6.8 million. The Company does not maintain this information such that it is able to provide a breakdown of the information for only those meters which will be replaced with AMF.

Rhode Island Energy's AMF Business Case and BCA propose the replacement of 524,677 electric AMR meters with electric AMF meters. Based on the data that was current at the time of the filing, Rhode Island Energy calculated meters to be replaced by taking a total count of meters at that time (530,878) and subtracting meters that were out of scope because they are read by the MV90 system (901 meters) and then subtracting anticipated opt-out meters (5,300) based on an estimated opt out rate of 1 percent.

Meter counts are constantly changing and will continue to change throughout the AMF deployment.

Below is a breakdown of the total number of meters by rate class:

Tariff	Tariff Description	Total
1	Elec A-16 Residential-Std Ofr	396,758
5	Elec C-06 Small C&I-Std Ofr Fixed	47,183
6	Elec A-60 Resi Low Income-Std Ofr	34,567
13	Elec G-02 Large C&I-Std Variable	4,268
34	Elec C-06 Sm C&I Unmetered-Std Ofr Fixed	55

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53	Elec G-02 Large C&I-Std Ofr Fixed	185
54	Elec C-06 Sm C&I Unmetered-Std Ofr Variable	4
55	Elec C-06 Small C&I-Std Ofr Variable	79
117	Elec B-32 C&I 200 kW Back Up Svc-Std Ofr	2
122	Elec B-32 T&D C&I 200 kW Back Up Svc	3
186	Elec G3Z Company Use-Std Ofr	7
188	Elec C0Z Company Use-Std Ofr	276
192	Elec G0Z Company Use-Std Ofr	22
700	Elec G-32 200 kW Dem PK/SH/OP-Std Ofr	91
705	Elec G-32 200 kW Dem PK/OP-Std Ofr	101
710	Elec G-32 T&D 200 kW Dem PK/SH/OP	408
711	Elec G-32 T&D 200 kW Dem PK/OP	433
903	Elec A-16 T&D Residential	29,213
905	Elec A-60 T&D Resi Low Income	4,489
924	Elec X01 T&D Elec Propulsion	1
943	Elec M-1 Opt A Station Pwr Delivery Svc	1
944	Elec M-1 Opt B Station Pwr Delivery Svc	2
950	Elec C-06 T&D Small C&I	10,181
951	Elec C-06 T&D Sm C&I Unmetered	2
954	Elec G-02 T&D Large C&I	3,843
	Total	**532,174**

The Company does record the capitalized meter installation cost separately. Below is a snapshot of the accounting for installation cost in the totals, and the bare cost and installation costs separately(37010 and 37030 shows Bare Costs; 37020 and 37035 show Install costs)

	Values		
Row Labels	**Sum of accum_cost**	**Sum of allo_res**	**Sum of net_value**
37010-RIELEC-METERS BARE COST (DOME	26,349,582.28	27,881,370.86	(1,531,788.58)
37020-RIELEC-METERS INSTALL COST (D	14,010,059.08	9,823,374.66	4,186,684.42
37030-RIELEC-LRG METER INSTALL BARE	17,365,219.28	13,533,173.51	3,832,045.77
37035-RIELEC-LRG METERS INSTALL COS	10,976,792.82	10,663,718.52	313,074.30
Grand Total	**68,701,653.46**	**61,901,637.54**	**6,800,015.92**

PUC 3-31

Electric ISR Meter Proposal

Request:

In the Electric ISR Docket No. 22-53-EL, Attachment 1 shows both the historical capital spending back to FY 2011 and the proposed spending for a 21-month period spanning CY 2023 and CY 2024. (see Bates page 110) The table indicates proposed spending on meters of $4.5 million over that period.

(a) Please explain why the Company is proposing this level of capital spending on the old technology meters over this 21-month period when the Company is proposing to replace all old technology meters with smart meters under the Company's proposed timeline by the end of CY 2025.

(b) Please also explain why the Company is forecasting meter expenditures exceeding $2.6 million per year for CY 2026 and CY 2027. (See Attachment 3 – Five-Year Budget; Bates page 115) Are these new AMF meters or the old technology?

Response:

The Company is responding to this question based on the supplemental budget for fiscal year ("FY") 2024 for the period April 1, 2023 through March 31, 2024 that it filed with the Public Utilities Commission on January 27, 2023 in light of the PUC's ruling at its January 20, 2023 Open Meeting.

a) Electric meter budgets were prepared and presented in the Electric ISR Docket No. 22-53-EL that maintain business-as-usual processes. With AMF Business Case approval, the processes and support of old electric meter technology will be transitioned accordingly; as a result, the proposed meter spending in the FY 2024 (April 1, 2023 – March 31, 2024) ISR would not necessarily be spent.

b) The forecasted meter expenditures of more than $2.6 million per year for FY 2027 and FY 2028 are for old AMR technology. As stated above, with AMF Business Case approval, the processes and support of old electric meter technology will be transitioned accordingly; as a result, the proposed meter spending in the FY 2027 and FY 2028 ISR would not necessarily be spent.

(This response is identical to the Company's response to PUC 1-29 in the Electric ISR Docket No. 22-53-EL.)

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PUC 3-32

Relationship to Gas Distribution Metering

Request:

Regarding AMR meter reading:

(a) Please explain the difference, if any, between (i) how the Company reads the electric AMR meters with drive-by meter reading and processes the electric consumption data for the electric business and (ii) how the Company reads the gas AMR meters with drive-by meter reading and processes the gas consumption data for the gas business.

(b) Please note the extent, if any, to which the Company's drive-by meter reading and data-gathering activities are shared and shared costs are allocated between the electric and gas businesses currently, including without limitation systems, FTEs, and/or meter reading vehicles.

Response:

(a) The business process for drive by meter reading of AMR meters is similar for electric and gas meters. Both electric and gas meters belonging to the designated route to be read are loaded into the drive by software. As the drive by vehicle travels the route, the reads for both electric and gas are collected. This data is then passed along to downstream systems for processing.

(b) The Company's drive by meter reading and data gathering activities are shared between electric and gas meters as described in the response to part (a). Separate accounting codes for electric and gas have been established, and these codes are used to track costs for labor, transportation and expenses. These codes are entered separately on timesheets based on actual time spent on either electric or gas drive-by activities. Drive-by meter reading systems costs are also allocated between electric and gas.

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PUC 3-33

Relationship to Gas Distribution Metering

Request:

On Bates page 36, the Business Case states: "The system also is designed to anticipate that it will need to capture gas usage from gas meters every hour and transmit it every four hours."

(a) Please describe how the Company is designing the AMF to accommodate gas metering that captures gas usage every hour.

(b) What is the incremental cost of creating this additional functionality?

(c) Are there any other enhancements being built into the design of any of the AMF systems to accommodate the gas business at some point in the future? If so, please identify and quantify the cost.

Response:

a) The Company is not designing the AMF system to accommodate gas metering that captures gas usage every hour, specifically. Rather, the quoted language refers to the design parameters for the AMF RF Mesh system. Those design parameters for the AMF RF Mesh design are described in the Company's response to Division 1-25. The Company has designed the AMF RF Mesh network for the current electric meter population. If gas meters are upgraded in the future, the Company will be able to leverage the RF Mesh system it is installing for AMF electric meters in most instances, with the exception of areas where gas and electric customers do not overlap. Depending on what gas endpoint technology is selected, gas meter data capacity is less than electric and in essence can be incorporated into the network designed for the electric AMF data.

b) There is no current incremental cost in the AMF Business Case to accommodate metering that captures gas every hour. If, in the future, the Company upgrades gas meters to be able to capture gas usage from gas meters every hour and transmit it every four hours, then the Company's current order of magnitude preliminary estimates are that it would need the incremental RF Mesh to service the Rhode Island Energy customers with gas-only in the northwest region of Rhode Island at an approximate cost of $168,000 for installation and $46,500 for ongoing network costs. These cost estimates following the same assumptions in the AMF Business Case BCA. This order of magnitude preliminary estimate is specific to the RF network only and does not include additional endpoint costs within the meter data management system and head-end system or metering hardware. A more specific data traffic assessment would need to be performed that includes the proposed gas endpoint technologies data requirements and system investments.

c) As described in part (a), above, the ability of the RF Mesh network to accommodate gas metering that captures gas usage every hour is not an enhancement to accommodate the gas business at some point in the future, and there are no such enhancements being built into the design of any of the AMF systems.

PUC 3-34

Relationship to Gas Distribution Metering

Request:

Bates page 51 of the Business Case states:

> "The proposed Electric AMF investment provides a platform for gas AMF that will have increased functionality over the present gas AMR system. New Ultrasonic AMF gas meters coupled with gas methane detectors can become "smart grid" cornerstones for the gas system offering. Rhode Island Energy intends to apply these technologies, which will use the Electric AMF communication network to replace the gas AMR infrastructure with Ultrasonic gas meters and methane gas detectors having functionality that offers more granular gas information, sensing, remote disconnect, much-needed operational visibility and capabilities for increased customer awareness that leapfrogs the AMR capability that is available today."

Bates page 57 also states:

> "Deployment of Gas Methane Detectors and Ultrasonic gas meters are being analyzed in conjunction with the Long-Term Gas Strategy. Preliminary plans are underway for accelerated deployment of methane detectors and Ultrasonic Gas Meters beginning after the Electric AMF has been completed starting in 2025."

Bates page 227 also states:

> "In addition to avoiding the need for cellular communication augmentation, Rhode Island Energy's communication network design is sized for more data throughput than the National Grid's system which the Company believes will be critical for a future with more DERs, electric vehicles, clean energy, and to support AMF for gas customers."

(a) Please explain in more detail how the Electric AMF communication network will be used to support the replacement of the gas AMR infrastructure.

(b) Please also describe any enhancements to the AMF system, if any, which the Company expects would be needed in 2025 to accommodate the deployment of the methane detectors and Ultrasonic Gas Meters, which will not already be designed into the AMF prior to 2025. Please provide a cost estimate.

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Response:[1]

a) The AMF RF Network could enable the seamless support of gas metering solutions on the same network platform that is being developed for the electric metering solution. Gas endpoints, such as Ultrasonic, AMR, and methane detectors, could communicate and operate over the same shared network as electric meters. The network would be managed by a single Network Management System ("NMS"), with data flowing into the same Headend System ("HES").

   For example, Ultrasonic gas meters include built in communication modules that would join the RF Mesh network and benefit from the flexibility, resiliency, and end-to-end security of the electric AMF metering solution. The gas communication module is anticipated to act as an endpoint on the network and participate in the RF mesh network through an associated electric meter, or other designated network device, that acts as its lead endpoint to communicate to and from the HES. All of the traffic from the lead endpoint to the HES follows the same security and encryption methodologies throughout the solution. Gas methane detectors could also be endpoints that use the electric meter or other designated network device to communicate alarms to the control center. In conclusion, both the electric AMF RF communication network and the AMF electric meter can play important roles in supporting the replacement of the gas AMR infrastructure and upgrading the gas metering and sensing technology.

b) The Company understands that the long-range gas strategy assessment in the Future of Gas Docket that is underway is intended to guide future gas investments. If gas metering upgrades are embraced by the assessment, the Company intends to conduct an analysis to determine the best option for gas metering upgrades. See the Company's response to PUC 3-37. To enhance the AMF to accommodate gas upgrades requires system development to accommodate granular gas data and potentially alarms from Gas Methane Detectors. A preliminary investment estimate for this system development work was identified in the Gas ISR in 2025 and 2026. See the Company's response to PUC 3-36. Please see the Company's response to PUC 3-33 for the Company's estimate of the incremental cost to expand the RF Mesh network to cover the Rhode Island Energy customers with gas-only in the northwest region of Rhode Island.

[1] The Company notes that the quoted language attributed to Bates Page 57 of the AMF Business Case appears on Bates Page 55 of the AMF Business Case.

PUC 3-35

Relationship to Gas Distribution Metering

Request:

Page 14 of 84 of the Testimony of Walnock & Reder it states:

> "Q. Does the AMF Business Case include a proposal for the deployment of AMF meters across the Company's gas distribution system?
>
> A. No. The Company is developing a long-range gas strategy assessment for Rhode Island. The gas metering infrastructure and Rhode Island's future needs will be considered in the assessment, and, if viable, the Company will utilize the fixed communication network established in this AMF proposal to support upgraded gas metering and sensing capability in Rhode Island."

(a) Please reconcile this statement in the testimony with the statements in the Business Case at Bates pages 36, 51, 57, and 227 which state the Company's intention is to replace the gas meters.

(b) If the Company believes it is possible that such gas meter replacement would not be viable, please explain in technical detail why it might not be viable to replace the existing gas meters with new gas meter technology that could beneficially use the AMF technology with "functionality that offers more granular gas information, sensing, remote disconnect, much-needed operational visibility and capabilities for increased customer awareness that leapfrogs the AMR capability that is available today."

(c) Is there anything that prevents the Company from completing a reasonably reliable assessment of upgrading the gas metering system within the next six months?

Response:

a) The Company understands that the long-range gas strategy assessment in the Public Utilities Commission's Future of Gas docket (Docket No. 22-01-NG) is intended to guide future gas investments. The Company included gas technology modernization as possible examples of future applications that AMF enables to demonstrate how it is a strategic platform that can be built upon to provide incremental value beyond the AMF Business Case. The statements in the AMF

Business Case regarding gas metering technology, including those at Bates pages 36, 51, 55, 61, and 227,[1] were intended to describe how the Company's proposed AMF solution enables the ability to replace the existing gas meters with new gas meter technology.

(b) The Company believes that it is viable to replace the existing gas meters that use AMR with new gas meter technology that would utilize the AMF technology.

(c) No, there is nothing preventing the Company from completing a reasonably reliable assessment of upgrading the gas metering system within the next six months.

[1] The Company did not identify any statements on Bates page 57 of the AMF Business Case that relate to the potential future replacement of gas meters.

PUC 3-36

Relationship to Gas Distribution Metering

Request:

In the Gas Infrastructure, Safety and Reliability Docket No. 22-54-NG, Section 2 of the Gas Capital Investment Plan (Bates page 50) states that Company will purchasing over 34,000 new gas meters (14,820 in CY 2023 and 19,759 in CY 2024) at a total cost of $13.47 million ($5.91 in CY 2023 and $7.56 million in CY 2024). The filing also states on the same page: "These purchasing volumes reflect the Company's efforts to compensate for ongoing meter supply chain issues by increasing our baseline inventory."

Further, in the same filing at Table 2 (Bates page 82) there is a projected budget line item of $2,250,000 in FY 2025 and $750,000 for FY 2026, labeled as "Smart Gas Meter – IS Integration."

(a) Please explain why the Company plans on spending $13.47 million to increase inventory of old version gas meters when there appears to be a significant likelihood that the Company will commence an accelerated deployment of new Ultrasonic Gas smart meters in 2025 (See Bates page 36, 51, 57, and 227 of the Business Case).

(b) Please describe the Smart Gas Meter – IS Integration.

(c) If the purchase of the meters is driven by the mandatory nature of some meter replacements, is there any reason why the Company should not or could not seek a waiver from the Commission for at least a portion of the meter replacement mandate in 2025 in order to avoid purchasing gas meters that are reasonably likely to be replaced?

Response:

(a) The Company anticipates that electric meter upgrades will occur before gas meter technology upgrades. If the Commission approves the Company's proposed AMF Business Case, the processes and support of old electric meter technology will be transitioned accordingly. Assuming that the Commission's pending Future of Gas docket (Docket No. 22-01-NG) to investigate the future of the gas distribution business within the context of the Act on Climate supports gas meter and sensing upgrades, then the

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Company will begin pursuing gas meter technology upgrades, outside of the Future of Gas docket, after the electric AMF deployment. Until any gas meter technology upgrades are approved (or pending approval), the Company is maintaining a business-as-usual approach to its meter exchange program. The Company is open to modifying the existing gas meter exchange program to better align with any future technology deployments.

(b) The Smart Gas Meter – IS Integration is anticipated capital for software development needed to have the functionality available to integrate advanced gas metering technology into other systems. This integration would need to be largely completed before gas meters can be exchanged. The capital investment is anticipated in 2025 and 2026 and identified for transparency, though not currently included in the Company's FY 2024 Gas ISR Plan proposal before the Commission in Docket No. 22-54-NG.

(c) In the future, if and when there is reasonable certainty that the gas meter technology will be upgraded, the Company would likely transition its purchasing strategy, at which time it may be reasonable to seek waivers from the Commission for at least a portion of the meter replacement mandate to avoid purchasing gas meters that are reasonably likely to be replaced with new gas metering technology.

(This response is identical to the Company's response to PUC 1-1 in the Gas ISR Docket No. 22-54-NG.)

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

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PUC 3-37

Relationship to Gas Distribution Metering

Request:

The National Grid AMF proposal included the installation of AMF-enabled gas modules. Did Rhode Island Energy consider installing such gas modules as an alternative to either leaving the existing AMR technology in place or deploying the ultrasonic gas meters as referenced in the Rhode Island Energy Business Case at Bates page 51? If not, why not? If yes, please describe and explain the assessment, including the reasons why Rhode Island Energy rejected the AMR-compatible gas module alternative and any cost comparison that was done to make the decision.

Response:

Gas meter reading was not included in the AMF Business Case because the Company expects the long-range gas strategy assessment in the Future of Gas Docket that is underway is intended to guide future gas distribution system investments. Accordingly, the Company did not consider proposing the installation of AMF-enabled gas modules as part of the AMF Business Case, and the Company did not perform a cost comparison as part of making that decision.

For clarity, the Company also is not proposing to deploy ultrasonic gas meters as part of the AMF Business Case. The Company described the possibility for gas technology modernization as possible examples of future applications enabled by AMF to illustrate how it is a strategic platform that can be built upon to provide additional value beyond what is set forth in the AMF Business Case. Preliminarily, future gas meter reading technology options include maintaining the existing AMR system, upgrading with AMF-gas module replacements, and upgrading with AMF-enabled Ultrasonic meters. If the Future of Gas Docket embraces the need for new gas meter reading technology, an analysis that evaluates gas meter reading options will follow to determine the appropriate course of action to meet present and future requirements, and that evaluation likely will include a cost comparison of the options.

Prepared by or under the supervision of: Wanda Reder

PUC 3-38

Relationship to Gas Distribution Metering

Request:

What is the status of AMF deployment in Kentucky for electric and gas meters? What gas metering technology does the PPL gas distribution affiliate in Kentucky utilize currently and what technology is PPL anticipating that it will use for after deployment of AMF for the electric business? If not AMF-compatible gas meters or modules, are there any plans for the affiliate to deploy new AMF-compatible meters or another AMF-compatible technology?

Response:

The Company's Kentucky affiliates' Advanced Meter Infrastructure ("AMI") implementation plan was approved on June 30, 2021[1] and includes the deployment of communicating AMI modules on approximately 320,000 gas meters of the roughly 340,000 total gas meters.[2] The phased installation of new RF mesh communication network equipment, advanced electric meters and communicating gas modules began on schedule in the fall of 2022 and is scheduled to continue through 2025. Approximately 45,000 AMI gas modules and AMI electric meters have been installed of the roughly 1.3 million total. A live status map of the geographic deployment can be found on this AMI Deployment Update website: https://experience.arcgis.com/experience/1659773d752048b5a2c99f518d449328.

Additionally, the Company files quarterly status reports to the Kentucky Public Service Commission, which can be found here: https://psc.ky.gov/Case/ViewCaseFilings/2020-00350/Post. Although the Company continually assesses technology to best serve customer needs, there are no known additional changes to the gas metering technology after completion of the AMI deployment.

[1] Application of Kentucky Utilities Company for an Adjustment of Base Rates, Case No. 2020-00349; Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates, Case No. 2020-00350.

[2] The Company's Kentucky affiliate's gas metering consists of a mixture of diaphragm and rotary meters, and its gas service territory consists of both dual-service (the Company provides both electric and gas service) and gas-only territories. In the dual-service territory, the Company will be installing AMI modules on the existing gas meters. In the gas-only territory, consisting of roughly 19,000 gas meters, the Company plans to utilize Encoder Receiver Transmitter ("ERT") modules. Additionally, Kentucky has two populations of gas meters that are not part of the approved AMI implementation, which include the large pad diaphragm meter, representing ~175 meters, and roughly 2,400 gas rotary meters, which are not compatible with the AMI module and would require the meters to be replaced or an index retrofit.

Prepared by or under the supervision of: Philip J. Walnock and William J. Hennegan