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February 17, 2023

VIA ELECTRONIC MAIL AND HAND DELIVERY

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

Re: The Narragansett Electric Company d/b/a Rhode Island Energy
In Re: Advanced Meter Functionality Business Case – Docket No. 22-49-EL

Dear Ms. Massaro:

Enclosed please find an original and nine copies of The Narragansett Electric Company d/b/a Rhode Island Energy's (the "Company") Supplemental Memorandum in Support of Its Renewed Motion for Protective Treatment of Confidential Information. This filing provides further support for the Company's renewed request for protective treatment of its Benefit-Cost Analysis ("BCA") for the Advanced Meter Functionality Business Case and for protective treatment of discrete, limited portions of the companion BCA Narrative. An updated proposed redacted version of the BCA Narrative is included as Exhibit 1 to the filing.

Thank you for your attention to this matter. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Adam M. Ramos

Enclosures

cc: Service List 22-49-EL (via e-mail only)

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-49-EL Advanced Meter Functionality (AMF)
Service list updated 2/9/2023

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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 SUPPLEMENTAL MEMORANDUM IN SUPPORT OF ITS RENEWED MOTION FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") submits this Supplemental Memorandum to further explain why the limited redactions in the BCA Narrative of Attachment H to the Company's Advanced Metering Functionality Business Case (the "AMF Business Case") are necessary to protect confidential and proprietary commercial and financial information. This information falls squarely within the Access to Public Records Act's exemption from public disclosure. The Rhode Island Public Utilities Commission ("PUC") has maintained confidential treatment of Attachment H pending a ruling on the Company's motions.

For the reasons 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), and permit public disclosure only of the proposed redacted version attached as Exhibit 1. The Company also requests that, pending entry of this ruling, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2) until a ruling enters.

I. BACKGROUND

When the Company initially filed its AMF Business Case on November 18, 2022, it included a Motion for Protective Treatment of Confidential Information, seeking confidential treatment of certain documents—namely, its AMF Benefit-Cost Analysis ("BCA") Spreadsheet in Excel format (the "BCA Model") and related Narrative (the "BCA Narrative") contained in Attachment H to the AMF Business Case.[1] After an initial review, the PUC concluded that the request for confidential treatment for the entire Attachment H was overbroad and permitted the Company to narrow the request before issuing a final ruling. Accordingly, on January 31, 2023, the Company filed its Renewed Motion for Confidential Treatment, which included a redacted version of the BCA Narrative and a table explaining the need for each redaction. In a ruling dated February 6, 2023, the PUC asked the Company to further justify the need for redactions, including specifically: (1) why redactions are necessary for information that might be produced in a distribution rate case without confidential treatment; (2) why information that originated from National Grid USA ("National Grid") requires confidential treatment; and (3) how the transparency of the evidentiary hearings and public confidence in the process will be impacted if the PUC treats this information as confidential.

Accordingly, the Company submits this Supplemental Memorandum in Support of Its Renewed Motion for Protective Treatment of Confidential Information. The Company again has analyzed every aspect of the BCA Narrative to determine whether portions could be made public

[1] When the Company initially filed the BCA Narrative and requested that it be maintained as confidential in its entirety, the Company did so based on its view that the BCA Narrative served as a companion document to the BCA Model, which is a confidential and proprietary model developed by the Company. The Company provided the BCA Narrative as a tool to navigate and understand the BCA Model inputs. Accordingly, the Company assessed the BCA Narrative as inextricably intertwined with the BCA Model and sought confidential treatment for the BCA Narrative in its entirety. After receiving initial feedback on that request, the Company reassessed the BCA Narrative as a standalone document and proposed only minimal redactions of sensitive confidential information contained with the BCA Narrative.

without jeopardizing sensitive interests. The Company also has conferred with National Grid to assess the confidentiality needs for National Grid's information. The remaining information for which the Company requests confidential treatment consists of commercially sensitive pricing and salary information, and information for which the Company has certain confidentiality obligations, which are explained in further detail below.

In short, the Company seeks redactions of three narrow categories of information in the BCA Narrative: (1) the competitively negotiated price for certain products (e.g., unit costs of meters and software); (2) the salary costs for positions that have not yet been filled or may need to be augmented and bid in the future; and (3) information that the Company received from National Grid, which National Grid has asked the Company to treat as confidential.

II. <u>LEGAL STANDARD</u>

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

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

III. <u>BASIS FOR CONFIDENTIALITY</u>

The information proposed for redaction in the BCA Narrative constitutes "commercial or financial information" to which the APRA public disclosure requirements do not apply. *See* Gen. Laws § 38-2-2(4)(B); *Kane*, 577 A.2d at 663. Specifically, the redactions cover three types of confidential and proprietary commercial and financial information: (1) the competitively negotiated price for certain products (e.g., unit costs of meters and software); (2) the salary costs for positions that have not yet been filled or that may need to be augmented and bid in the future; and (3) information that the Company received from National Grid that National Grid has requested the Company keep confidential. Disclosure of the vendor information may impact the Company's ability to negotiate favorable pricing for Rhode Island customers in the future. Similarly, disclosure of the salary-related information for future positions or strategy information still under development may impact the Company's ability to fill positions or achieve strategic outcomes, putting the Company and Rhode Island customers at a disadvantage. Finally, the Company has confidentiality obligations to National Grid that require it to request confidential treatment of National Grid's information. For all of these reasons, the portions of the BCA Narrative for which the Company seeks confidential treatment are not public information to which APRA applies.

A. Confidentiality basis for competitively negotiated purchases of products

The Company has redacted information relating to the competitively negotiated prices for certain products, including the unit costs of meters (BCA Narrative at 25), and annual and total costs of software (BCA Narrative at 27, 29, 32, 33, and 35). The Company ordinarily does not make this information available to the public. Rather, the Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding. Therefore, this information satisfies the APRA exception found in Gen. Laws § 38-2-2(4)(B).

Regarding the unit costs of meters, these prices were carefully negotiated with the Company's third party vendor. The vendor provided this pricing information confidentially to the Company and disclosing this information would place the vendor at a competitive disadvantage. In particular, the third-party vendor provided the information under the express condition that the Company could only "use and disclos[e]" the information for the specific purpose for which it was provided or "as required by law." Although the condition authorizes disclosure required by law, at most that authorizes disclosure to the PUC for purposes of evaluating the Company's AMF Business Case, but only on a confidential basis.

The need to maintain this information as confidential is important to the Company and to the third-party vendor. The Company must maintain its commercial relationships with its vendors to be able to continue to deliver safe and reliable service affordably. For the third-party vendor, the pricing information, if associated with that third-party vendor, puts it at a competitive disadvantage with respect to its competitors. Accordingly, it is important to keep this competitive pricing information about unit costs of meters confidential so as not to jeopardize the Company's ability to negotiate vendor agreements, which is critical to the successful implementation of not only the Company's AMF Business Case, but also the Company's overall ability to continue delivering safe and reliable service affordably.

Like the unit costs of meters, the annual and total costs for software reflect negotiated pricing between the Company and its vendors. The vendors provided these prices confidentially to the Company. Publicly disclosing this information may impact the Company's commercial relationships with these vendors and place these third-party vendors at a competitive disadvantage in the marketplace. For all of these reasons, this information constitutes "commercial or financial information" to which APRA does not apply.

Further, keeping this competitive pricing information confidential should not affect the transparency of the evidentiary hearings or public confidence in the PUC's review of the AMF Business Case. The public has access to extensive information in the AMF Business Case regarding the functionalities and intended uses of these products. The AMF Business Case also contains information regarding aggregate benefits and costs of the proposal, along with BCA information. In total, this public information provides a substantial basis to evaluate the functionalities and benefits of these investments and weigh them against the anticipated costs. Disclosure of unit pricing is not necessary to that analysis, particularly where such disclosure risks harm to the Company and ultimately its customers.

B. Confidentiality basis for salary costs

The Company has redacted salary costs for certain positions and roles in connection with AMF. These include the following: technology support services (BCA Narrative at 27, 29-30, 32-34), including those related to TVR (BCA Narrative at 31); AMF operations and support services (BCA Narrative at 35); AMF project management support services (BCA Narrative at 36); and the Change Management department (BCA Narrative at 37). The Company ordinarily does not make this type of salary information available to the public. Rather, the Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding. Therefore, this information satisfies the APRA exception found in Gen. Laws § 38-2-2(4)(B).

These salary costs reflect a number of confidential interests. In some instances, these are salaries for positions or roles that do not currently exist and for which the Company will need to go to the marketplace and hire employees. In other instances, the Company may need to augment or bid out positions in the future. Publicly revealing these salary numbers may impact the Company's ability to hire qualified individuals for these positions. In certain categories, such as change management, the labor rates reflect the rates of third-party vendors. Disclosing this information could place the Company at a competitive disadvantage to other employers who may outbid the Company in a competitive labor market and potentially create project cost overruns or with its commercial vendors interested in keeping this information confidential.

Additionally, as with the pricing information, revealing these salary costs is not necessary for the public to assess the reasonableness and appropriateness of these expenses as part of the AMF Business Case. The AMF Business Case, along with the unredacted portions of the BCA Narrative, describes the duties and responsibilities of these roles, as well as the types of technology for which they will have responsibility. This information will allow the public and intervenors to adequately assess the value these investments will add to the AMF Business Case.

C. Confidentiality basis for information obtained from National Grid

Finally, the Company has redacted certain confidential information it received from National Grid as part of the sale transaction, including the following: the benefits used in National Grid's AMF Business Case BCA (BCA Narrative at 21-22) and a comparison chart of National Grid and Rhode Island Energy AMF BCAs (BCA Narrative at 39). The Company has redacted this information based on National Grid's request that it treat this information as confidential.

National Grid originally moved for confidential treatment of this information when filing its Updated AMF Business Case in Docket No. 5113. Because the Company filed a Notice of Withdrawal of the Updated AMF Business Case on September 19, 2022, the PUC never ruled on National Grid's motion. When National Grid provided the information contained in the BCA Narrative to Rhode Island Energy, it did so confidentially. Prior to filing this supplemental motion, the Company contacted National Grid to determine whether the information included in National Grid's BCA required continued confidential treatment. As reported to the Company, National Grid considers the BCA information confidential because it includes vendor meter pricing provided under specific circumstances pursuant to a request for production. National Grid has continuing obligations to its potential vendor to keep this pricing information confidential. The Company, therefore, has an obligation to seek to maintain this information as confidential before the PUC in this proceeding.

Keeping this National Grid information confidential should not affect the transparency of the evidentiary hearings or public confidence in the PUC's review of the AMF Business Case.

The AMF Business Case also contains information regarding aggregate benefits and costs of the proposal, along with BCA information. The National Grid information comprises a small portion of these overall benefits and costs. The public information provides a substantial basis to evaluate the functionalities and benefits of these investments and weigh them against the anticipated costs.

Accordingly, as set forth in its Renewed Motion for Confidential Treatment, Rhode Island Energy respectfully requests that the PUC grant protective treatment to the BCA Model and the portions of the BCA Narrative proposed for redaction and take the following actions to preserve their confidentiality: (1) maintain the BCA Model and unredacted versions of the BCA Narrative as confidential indefinitely; (2) not place the BCA Model on the public docket and place only the redacted versions of BCA Narrative on the public docket; and (3) disclose the BCA Model and the unredacted versions of the BCA Narrative 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

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Dated: February 17, 2023

CERTIFICATE OF SERVICE

I hereby certify that on February 17, 2023, I sent a copy of the foregoing to the service list
by electronic mail.

/s/ Adam M. Ramos

EXHIBIT 1

Benefit Cost Guide Memo

November 2022

Benefits Guide: Estimated for Rhode Island Energy AMF Business Case[1]

Introduction

This Benefits Guide is intended to be a companion piece to the AMF Meter Project Benefit-Cost Analysis spreadsheet. The benefit explanations are presented in the order they appear in the spreadsheet. This is intended only as an aid to interpreting the calculations of the benefits presented in the spreadsheet.

Benefit #2: Reduced AMR Meter Readers

This benefit was calculated by first adding the salary of the meter readers, their phone cost, and their uniform cost; the salary values were inflated by 2.5% (labor escalation rate) and the phone and uniform values were inflated by 2.3% (non-labor escalation rate). The Company estimated that 8 meter reading FTEs would not be needed with AMF electric meters. The result was multiplied by .99 due to the 1% AMF meter opt out and added to the meter reader maintenance bill. The Benefit Achievement Rate (BAR) starts at 50% in 2025 and reaches 100% in 2026. This indicates that half of the FTE positions will be reduced in 2025 and all the FTE positions will be reduced starting in 2026; the benefit continues throughout the 20-year analysis period. Savings are calculated for each year from 2022-2041 and summed to get the nominal benefit savings. The Net Present Value of the benefit was calculated using the Company's Weighted Average Cost of Capital (WACC) which is 6.97% post tax.

The Company used National Grid's values for the cost of individual meter readers, assuming that the values were $2020. The Company made this change to reflect that the AMF project is addressing only electric and not electric and gas. Meter readers are still needed to read the gas meters.

The result is a total nominal benefit of $11.19 million and an NPV of $4.97 million ($2022).

Benefit #3: Reduced AMR Meter Reader Vehicle Costs

Each meter reader has 1 vehicle assigned to them, so in addition to eliminating the FTEs, the Company calculated the benefit of reducing the number of vehicles used as well. This benefit was calculated by multiplying of the number of reduced meter reader vehicles by .99 due to the 1%

AMF meter opt out and multiplying that value by \$18,000/year/vehicle (the average total cost of a vehicle in \$2020) to get the annual total dollar savings. The annual benefit is inflated by 2.30%/year to determine the annual savings in nominal dollars. The escalation rate is the Non-Labor Escalation rate. The Benefit Achievement Rate (BAR) is the same as the reduced meter reader FTEs, starting in 2025 at 50%, increasing to 100% in 2026 and thereafter. The annual benefits were summed to determine the nominal benefit savings and discounted by the WACC (6.97%) to determine the Net Present Value (NPV) of the benefit.

As with the reduced meter reader FTEs, the Company reduced meter reader vehicles by 8 as opposed to 14, as National Grid did. The values used for calculating this benefit were the same values used by National Grid except for reducing the number of vehicles.

The result is a total nominal benefit of \$3.20 million and an NPV of \$1.43 million (\$2022).

Benefit #4: Non-Embedded CO2 Benefit: Eliminated AMR Vehicles

Eliminating 8 vehicles also eliminates CO2 emissions. This benefit was calculated by multiplying the Total Feeder Miles with the number of times feeder length is driven to get Annual miles driven/vehicle. The Fuel economy for AMR reading vehicle was estimated at 15.2 miles/gallon of diesel fuel. The CO2 content of diesel fuel 22.45 lbs CO2/gallon. The miles driven/year were divided by the miles/gallon and multiplied by the CO2 to determine the amount of CO2 no longer being emitted by one vehicle. This value was multiplied by .99 due to the AMF meter opt-out assumption. This is divided by 2000 to get the CO2 emissions in tons, then multiplied by the 8 vehicles reduced. The social cost of CO2 is estimated at \$51/ton (\$2022). This cost is multiplied by a Societal Inflation Rate of 2% annually to determine nominal cost/ton CO2. The nominal cost/ton of CO2 is multiplied by the total tons reduced and by the Benefit Achievement Rate. The Benefit Achievement Rate starts in 2025 at 50%, reaches 100% in 2026 and remains 100% throughout the study period.

The number of feeder miles (6012), number of times driven annually (12), and the meter reading vehicles/meter reader (1) were National Grid estimates that Rhode Island Energy adopted. The social cost/ton of CO2 was sourced from EPA. Because this is a societal benefit, a societal discount rate of 3% was used to develop the Net Present Value.

The total nominal benefit from reduced CO2 totals \$0.45 million nominal and \$0.32 million NPV (\$2022).

Benefit #5: Reduced Meter Investigations

This benefit was calculated by determining the number of FTEs reduced that were related to Meter Reading (other than the Meter Readers who were discussed above) and to Meter Field Investigations. The total FTE reduction is estimated to be 8, 6 related to Meter Reading and 2 related to Field Investigations. The Meter Reading Annual Salary (loaded $2020) is applied to the 6 Meter Reading FTEs reduced (less 1% AMF Opt-Out). The Field Services Annual Salary (loaded $2020) is applied to the 2 FTE reductions in Field Investigations (less 1% AMF Opt-Out). The vehicle cost, annual uniform cost and annual phone cost are applied to all 8 FTEs reduced (less 1% AMF Opt-Out). These values are multiplied appropriately and divided by $1 million to get the annual savings in $millions. Each of these total values were developed separately to allow for inflating them by different values to get nominal dollars. The salary values were inflated by 2.5% annually and the vehicle, uniform and phone costs were inflated by 2.3% annually. The annual values (in $million nominal) were summed for each year and multiplied by the Benefit Achievement Rate (BAR). The BAR begins in 2025 at 50%, increases to 100% in 2026 and remains at 100% throughout the study period. The annual results of this multiplication were then summed to get the total nominal benefit and discounted at the utility's after-tax Weighted Average Cost of Capital (WACC- 6.97%) to determine the Net Present Value ($2022) of the benefit.

The salary values and values for the cost of vehicles, phones and uniforms were developed by National Grid and used by the Company. The FTE reductions were developed by reviewing PPL-PA's achieved FTE reductions resulting from installing AMF meters; PPL-PA was able to reduce overall non-meter reader FTEs by 52% after installing AMF meters. The percentage reductions achieved by PPL-PA were applied to a count of the existing Rhode Island Energy meter and field investigation personnel to determine the number of FTEs that could be reduced in Rhode Island and allocated between Reduced Meter Investigations and Remote Metering Capabilities (below). The 1% AMF meter Opt-Out is the same as what was assumed by National Grid. The labor and non-labor escalation rates and the After-tax WACC were developed by National Grid and adopted by the Company.

The total nominal benefit from Reduced Meter Investigations is $17.09 million and the NPV is $7.63 million ($2022).

Benefit #6: Remote Metering Capabilities

This benefit was calculated by determining the number of FTEs reduced that were related to Remote Metering Capabilities. The total FTE reduction is estimated to be 27.2, 13.6 related to Meter Oriented Services and 13.6 related to Field Collections. The Meter Reading Annual Salary (loaded $2020) is applied to the 13.6 Meter Oriented Services FTEs reduced (less 1% AMF Opt-Out). The Field Services Annual Salary (loaded $2020) is applied to the 13.6 FTE reductions related to Field Collections (less 1% AMF Opt-Out). The vehicle cost, annual uniform cost and annual phone cost are applied to all 26.9 FTEs reduced (less 1% AMF Opt-Out). These values are multiplied appropriately and divided by $1 million to get the annual savings in $2020millions. Each of these total values were developed separately to allow for inflating them by different values to get nominal dollars. The salary values were inflated by 2.5% annually and the vehicle, uniform and phone costs were inflated by 2.30% annually. The annual values (in $million nominal) were summed for each year and multiplied by the Benefit Achievement Rate (BAR). The BAR begins in 2025 at 50%, increases to 100% in 2026 and remains at 100% throughout the study period. The annual results of this multiplication were then summed to get the total nominal benefit and discounted at the utility's after-tax Weighted Average Cost of Capital (WACC- 6.97%) to determine the Net Present Value ($2022) of the benefit.

The salary values and values for the cost of vehicles, phones and uniforms were developed by National Grid and used by the Company. The FTE reductions were developed by reviewing PPL-PA's achieved FTE reductions resulting from installing AMF meters; PPL-PA was able to reduce overall non-meter reader FTEs by 52% after installing AMF meters. The percentage reductions achieved by PPL-PA were applied to a count of the existing Rhode Island Energy meter and field investigation personnel to determine the number of FTEs that could be reduced in Rhode Island and allocated between Reduced Metering Capabilities and Reduced Meter Investigations (above).

The total nominal benefit for Remote Metering Capabilities is $55.63 million and the NPV is $24.73 million ($2022).

Benefit #13: Electricity Theft Reduction – Transfer Payment

This benefit is a transfer payment between groups of customers – reducing the theft increases the amount those stealing electricity pay and reduces the amount the rest of the customers pay. As a transfer payment it is not included in the sum of benefits to determine the benefit/cost ratios.

This benefit was calculated by developing the Annual Customer Revenue (in $MM), which is a combination of a forecast of energy use by customer class from 2022 through 2041 and a forecast of electricity prices by customer class for each year. The values for the customer classes are summed each year and multiplied by the Reduction of Theft Loss due to AMI (%), which is assumed to be 0.25% of total revenues. The values were reduced by 1% due to the 1% AMF Meter Opt-Out. The Benefit Achievement Rate (BAR) begins in 2026 at 25% and reaches 100% in 2029. The annual values were summed to determine the Nominal benefits and discounted at the Utility discount rate (6.97%) to determine the $2022 Net Present Value of the benefit.

The energy forecast was developed using a combination of historical information on growth rates by customer class, the GWh Delivery forecast developed by National Grid to 2026 and a forecast developed for use in the AMF and Grid Modernization analyses which is designed to meet Rhode Island's Climate Mandates. This forecast includes significant penetrations of Electric Vehicles

(EVs), Electric Heat Pumps (EHPs) and Distributed Energy Resources. The price forecast was developed using historical price increases for the last 20 years and does not reflect the most recent significant increases in energy supply costs. In addition, prices were held constant until 2026 to reflect the rate freeze agreed to by PPL in the acquisition of Rhode Island Energy. The percent reduction in theft (0.25%) was developed through industry research.

The total nominal benefit for Electric Theft Reduction $60.61 million and the NPV is $24.46 million ($2022).

Benefit #14: Energy Benefit from VVO/AMF integration

This benefit is calculated using the total forecasted energy referenced above reduced by 10% to reflect the 45 feeders (out of 484) that already have VVO/CVR capability and multiplying that load by a 0.5% energy reduction due to CVR attributable to AMF data. This amount of energy was then multiplied by .99 to reflect the 1% AMF Meter Opt-Out. These calculations provide the "Incremental Load Reduction Due to AMF data in CVR calculations (MWh)" which is multiplied by the Energy Price. The nominal annual energy prices were developed using the AESC 2021 Rhode Island Energy Costs ($2021), which varies from year to year and inflating them by the AESC Inflation Rate (2%). The MWh reduced by VVO/CVR are multiplied each year by the nominal $/MWh and the Benefit Achievement Rate. The BAR starts in 2026 at 20% and increases each year until it hits 100% in 2030. The discount rate used was AESC Discount Rate (2%).

The 0.5% energy reduction due to AMF meters was developed based on industry research which showed VVO/CVR savings ranging from 1% to 4.7% and from Rhode Island Energy's experience on two feeders where savings of 3.5% were achieved. VVO/CVR savings require Grid Modernization equipment and processes and the bulk of the benefits come from Grid Mod investments. There are additional benefits that are realized due to the increased visibility provided by the AMF meters and the Company has assumed that additional benefit will yield 0.5% energy savings.

This led to a total nominal benefit of $34.06 and an NPV of $25.61 (in millions) ($2022).

Benefit #15: Monetized CO2 benefit from VVO/AMF integration

The energy savings from VVO/CVR contribute to many benefits in addition to the energy savings. One of these is a reduction in CO2. The Company calculated the dollar value of this benefit by multiplying the "Incremental Load Reduction Due to AMF data in CVR calculations (MWh)" developed for Benefit #14 by the Monetized CO2 price ($2021 per MWh) - AESC 2021. The $2021 Monetized $/MWh from the AESC 2021 report were inflated by 2%/year to develop the nominal values. The nominal values were multiplied by the Benefit Achievement Rate to

determine the annual nominal savings due to CO2 reductions. The BAR starts in 2026 at 20% and increases each year until it hits 100% in 2030. The nominal values were discounted by the AESC Discount Rate (2%) to determine the NPV of the benefits.
This results in a total nominal benefit of $16.05 and an NPV of $11.96 (in millions) ($2022).

Benefit #16: Energy Savings: Energy Insights – Electric

The Company has assumed that customers who have more granular and much more timely data will reduce their energy use. This benefit was calculated by starting with the residential and commercial energy use/year forecast (GWh). The Residential energy use is multiplied by a 30% customer participation rate and the Commercial energy use is multiplied by a 25% customer participation rate to determine the Residential MWh Participating and the Commercial MWh Participating respectively. The residential and commercial MWh Participating values are summed and multiplied by 1.5% "Reduction due to Real-time data visualization" and .99 due to the 1% AMF Meter Opt-Out, and by 1,000 to get the Potential Consumption reduced (MWh). The Potential Consumption Reduced is multiplied by the annual energy cost savings in nominal dollars and by the Benefit Achievement Rate which starts in 2026 at 25% and hits 100% in 2029. The energy cost were developed using the AESC Energy cost savings ($/MWh in $2021) inflated by 2%/year to determine the annual nominal savings ($). The annual nominal savings are summed to determine the Total Nominal savings and discounted by 2%/year to determine the Net Present Value of the savings.

The 30% residential participation and the 25% commercial participation were based on 50% participation in PPL-PA's Customer Portal, an evaluation of National Grid-Rhode Island's energy efficiency programs from 2009-2015, and evaluations of Rhode Island Energy's Home Energy Reports Programs. The 1.5% savings was developed through industry research and review of the savings from the HER programs.

This led to a total nominal benefit of $31.10 and an NPV of $23.42 (in millions) ($2022).

Benefit #16.5: Electric Bill Reductions: Energy Insights

In addition to the energy savings calculated in Benefit #16, the Energy Insights will result in electricity bill savings for participating customers. These savings were calculated using the ultimate Residential MWh savings and the ultimate Commercial Energy savings. These savings are the Potential Consumption Reduced, whose derivations are described above, multiplied by the Benefit Achievement Rate. The annual savings are multiplied by a forecasted electricity price ($/MWh) for each of the Residential and Commercial classes. The forecasted prices began with the 2020 prices from Energy Information Administration. The prices are assumed to stay the same until 2026 due to the rate freeze agreed to with the sale transaction and then forecast to increase over time. The annual MWh savings are multiplied by the forecast electricity price to derive annual nominal bill savings for participating customers. These values are summed to determine the nominal savings and discounted by the Societal discount rate (3%) to determine the NPV ($2022) of the total bill savings for the Residential customers and for the Commercial customers. Because the energy benefit has already been counted in Benefit #16, it is subtracted from the total bill savings to avoid double counting.

The forecast annual electricity price increases used are 1.65% for Residential and 0.99% for Commercial. These were developed using historical growth rates for each of the classes.

This led to a total nominal benefit of $70.73 and an NPV of $44.02 (in millions) ($2022).

Benefit #17: Monetized CO2 Benefit: Energy Insights

This benefit is calculated by multiplying the Consumption Reduced (MWh), the derivation of which is described in Benefit #16, by the Embedded/Monetized CO2 price. The Monetized CO2 price was sourced from the AESC 2021 report which provides an estimate of this cost in $2021 per MWh. The annual prices developed in the AESC report are inflated by 2%/year to determine the nominal values. After multiplying the annual Consumption Reduced by the annual nominal prices, those values are summed to determine the total nominal savings. The annual nominal savings are discounted by 2%/year to calculate the Net Present Value savings. This benefit begins in 2026 at 25% and reaches 100% realization in 2029.

The assumptions behind the Consumption Reduced (MWh) are discussed above.

This led to a total nominal benefit of $14.58 and an NPV of $10.86 (in millions) ($2022).

Benefit #22: Faster Outage Notification

AMF meters automatically notify the utility when the power goes out rather than relying on the customer to call the utility to report a power outage. PPL-PA's deployed AMF meters several years ago and tracks the time difference between when they are notified of the outage and when the customer calls in (approximately 80% of the customers still call in the outage.) The time difference averages 22 minutes. While these 22 minutes are not included in utility reliability statistics (the clock starts when the utility is notified of the outage), it is an outage that the customer experiences. Rhode Island Energy used the Department of Energy's (DOE's) Interruption Cost Estimator (ICE) tool to determine the value of eliminating those 22 minutes of time. The ICE calculator determines the annual savings per customer by type of customer. These values were multiplied by the respective numbers for different customer types to determine an overall annual savings number which is $11.9 million/year, expressed in $2022.

Because this benefit accrues to customers directly, the appropriate escalation rate is the rate of inflation. The value was inflated at a 20-year average inflation rate of 2.0%, discounted by the 1% AMF Opt-Out rate and multiplied by the Benefit Achievement Rate to determine annual nominal savings for this benefit. The Benefit Achievement Rate (BAR) starts in 2025 at 50% and reaches 100% in 2026 and remains at 100% through the study period. The annual values were summed to determine the total nominal benefit and were discounted at the Societal Discount rate (3%) to determine the NPV of the benefit.

This result is a total nominal benefit of $243.79 and an NPV of $169.19 (in millions) ($2022).

Benefit #23: Avoided DSP Sensors

Utilizing AMF meters will eliminate the need for many of the Digital Signal Processing (DSP) sensors that the utility would need to install. Rhode Island Energy Subject-Matter Experts (SMEs) indicate that 2 sensors/feeder could be eliminated if AMF meters are installed. The total number of feeders is 484 and, of these, 45 already have DSP sensors, leaving 439 of the feeders needing sensors. The capital and installation cost of DSP sensors, ~$18,700/sensor, was estimated using historical data from Rhode Island Energy and information from vendors. In addition to the capital and installation costs, the total costs include Cost of Removal, Run the Business (RTB) and RTB-Telecom costs. Proportions of the total costs for each category were developed using National Grid's percentage distribution. This resulted in a total cost of DSP sensors of $22,600/feeder. The capital cost portion of the costs was inflated by 2.30% and the remaining (labor) costs were inflated by 2.50% to determine the nominal cost of installation each year. The individual components were multiplied by the Benefit Achievement Rate (BAR) which reflects the proportion of sensors expected to be installed each year.

Multiplying the annual nominal costs of each sensor by the BAR and the total number of feeders avoided provides an annual value for each portion of the feeder. The annual values are summed to determine the total nominal value and discounted at the WACC (6.97%) to determine the NPV of the benefit. Unlike most other benefits, this benefit is not adjusted for the AMF 1% Opt-Out rate because the sensors would be installed even though some customers opt-out of the AMF meter program.

The result is a total nominal benefit of $23.18 and a NPV of $14.36 (in millions) ($2022).

Benefit #24: Energy Shift Benefits: Electric Vehicle TVR

Rhode Island Energy was directed in the Amended Settlement Agreement to calculate the benefits and costs of going to Time Varying Rates. With AMF meters' granular and near-real time data provided to the utility and the customer, implementing Time Varying Rates can be much more sophisticated and effective. There are several benefits associated with TVR, including Energy shift benefits, capacity savings, transmission & distribution savings, and societal savings. In addition, due to the very significant increase in Electric Vehicles (EVs), Rhode Island Energy estimated the benefits of TVR for EVs separately from the benefits for "Whole House" Time-of-Use/Critical Peak Pricing (TOU/CPP) rates.

This particular benefit was calculated was by first taking the number of Electric Vehicles and then multiplying it by the annual Energy Use/EV (kWh) to get the Total Energy Usage all EVs (MWh). The Company forecast the percentage of energy that would be moved from on-peak hours to off-peak hours ("Energy Moved from On-peak to Off-peak due to TVR (%)" by participating customers. These values start at 12.8% in 2022 and increase to 27% in 2041 based on results from Rhode Island Energy's electric vehicle TOU pilot program.

The Company assumes the program will start in 2026 and reach steady-state participation and savings rates by 2034. The Company looked at two different options for TVR, an Opt-In approach and an Opt-Out approach. Each approach had different customer participation rates and different energy/peak savings rates over time. These are labeled "Annual Customer Participation Rate (%)" and the "Savings Ramp/Customer Rate (%)". The latter indicates how quickly the customer achieves 100% of the estimated savings; the assumption is that people will get better at saving over time. The Opt-In customer participation is assumed to be 20% and the Opt-Out customer participation rate is assumed to be 85%.

To determine the Opt-In savings, the Total EV energy use is multiplied by the Opt-In Annual Customer Participation rate, the Savings Ramp/Customer percentage, the MWhs of EV use and the % of usage shifted from on-peak to off-peak. The Opt-Out calculation uses the same approach. This determines the total MWhs shifted from on-peak to off-peak for each of the program options.

The total MWhs shifted are multiplied by the Energy cost differential between on-peak and off-peak. Avoided energy costs were sourced from the AESC 2021 Report which has values for both on-peak hours and off-peak hours in $2021. These values were inflated using a 2%/year rate to determine the annual nominal values. The difference in the on-peak and off-peak annual nominal costs were multiplied by the annual MWhs shifted to determine the annual nominal savings for this benefit. The annual nominal savings were summed to determine the total nominal savings for the benefit and discounted at the AESC discount rate of 2% to determine the NPV of the benefit.

The forecast of the number of EVs in Rhode Island Energy's area was developed using National Grid's Peak Forecast for Rhode Island (November 2021) and a forecast going out to 2050 which was designed to meet Rhode Island's Climate Mandates. The forecast starts at ~7,000 EVs in 2022 and increases to ~750,000 EVs in 2041.

The kWh used/EV was developed using National Grid's 2021 Peak Forecast, National Grid's 2021 Electric Delivery forecast, EVI Pro-Lite and the Rhode Island Energy EV TOU pilot program. The kWh/EV forecast is ~3,500 kWh/EV/yr. in 2022 and increases to ~4,300 kWh/EV/yr in 2041. The increase reflects the changing mix of EVs from primarily sedans to a more balanced mix of sedans and trucks and the increasing size of batteries to produce more power and distance.

The result is a total nominal benefit of $2.08 and an NPV of $1.51 (in millions) ($2022).

Benefit #25: System Capacity Benefit: EV TVR

In addition to Energy Shift benefits, EV TVR will produce peak savings. This benefit is calculated by first multiplying the number of Electric Vehicles forecasted each year by the kW contribution to System Peak/EV to determine Total kW contribution to system peak from EVs. The same program approach is used for all the TVR and Whole House TOU/CPP benefits with an Opt-In and an Opt-Out calculation with each having different customer participation rates (20% versus 85%) and different "ramp rates" for the participants to achieve 100% of the estimated savings. In this benefit calculation, the Total kW contribution to peak is multiplied by the Customer Participation Rate (%) and the Ramp Rate/Participating Customer. It is also multiplied by the percent peak reduction of EVs participating in the program, which starts at 29% in 2022 and increases each year until it reaches 60% in 2041. Finally, the AMF Opt-Out (1%) percentage is applied to determine the ultimate EV kWs reduced through Time Varying Rates.

To determine the value of the kW reductions, the Company used the avoided System Capacity Costs from the AESC 2021 Report which provides values in $2021 for each year. The System Capacity costs are expressed in $/kW. The AESC values were inflated by 2%/year to determine the nominal dollar avoided costs. These nominal values (in $/kW) are multiplied by the total EV kW reduction to determine the annual nominal benefit. The annual nominal $ values are summed to determine the total benefit and discounted by 2% to determine the total NPV savings.

The kW/Electric Vehicle contribution to the system peak was forecast using the DOE's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite. It is adjusted over time to reflect a changing mix of EVs from mostly sedans to a more balanced mix of sedans and trucks and the fact that the batteries used in EVs are getting larger to provide more power and distance between charges. The kW contribution is estimated at 0.64kW/EV in 2022 and increases to 1.38kW/EV by 204.

The percentage reduction at the time of the system peak is forecast based on Rhode Island Energy's EV TOU pilot program which demonstrated a range of peak hour reductions from 29%

to 60% depending on which hour the peak occurred. Rhode Island's peak is currently a summer peak, but it is moving later in the day and is ultimately forecast to become a winter peak.

The total nominal benefit is estimated at $43.41 and an NPV of $30.86 (in millions) ($2022).

Benefit #26: System Capacity Benefit: Whole House CPP

Whole House Critical Peak Pricing is a program in which customers receive rebates or deeply discounted rates during short periods of time or when a "Critical Peak Pricing" (CPP) event is called. Having customers reduce the system peak yields significant savings. This benefit is calculated by multiplying the Residential Contribution to Peak Load (MW) by the Peak Load Reduction estimate (20%) to determine the "Maximum Peak Load Reduction." The CPP program construct assumed is the same as the EV program construct; the Company assessed both an Opt-In approach and an Opt-Out approach with each of them having different Customer Participation Rates (%) and different Ramp Rates/Participating Customer (%). The assumptions for the Opt-In customer adoption and the Opt-Out customer adoption are the same as with EV TVR program – 20% participation for Opt-In and 85% participation for Opt-Out. The Ramp Rates/Participating customer are also the same as assumed in the EV TVR program. The Maximum Peak Load Reduction is multiplied by the annual participation rates and the annual ramp rate/participating customer to determine the Opt-In and Opt-Out Total peak MW reductions.

The annual peak MW reductions are multiplied by the avoided system capacity costs to determine the dollar value of the benefit. The avoided system capacity costs were sourced from the AESC 2021 Report and are expressed in $2021/kW-year and vary from year to year. The AESC 2021 values were inflated by 2%/year to determine the annual nominal avoided system capacity costs. These annual values were multiplied by the annual peak MW reductions to determine the annual nominal benefit. The annual values were summed to obtain the total nominal dollar savings and then discounted by 2% to determine the NPV of the benefit.

The Residential Contribution to Peak Load was developed using National Grid's 2021 Peak Forecast, National Grid's 2021 Distribution Delivery (GWh) Forecast, National Grid's estimate of the contribution of the Residential rate class to the system peak, historical residential customer counts and a forecast of Electric Vehicles and Electric Heat Pumps. National Grid's estimated contribution of the residential rate class was used to determine an overall percentage of the residential class contribution to the system peak. This percentage was multiplied by a forecasted system peak value considering only the reference system peak and the energy efficiency reductions to that reference peak. To that value were added the Residential EV peak load and the Electric Heat Pump load. This approach was taken because the overwhelming number of EVs will be residential, and it is assumed all the heat pump load will be residential.

The result is a total nominal benefit of $38.84 and an NPV of $28.58 (in millions) ($2022).

Benefit #27.5: Capacity Savings: Whole House Time-of-Use (TOU)

Benefit #27 is the Energy Shift Benefits from a Whole House Time-of-Use (TOU) program. The Company adopted National Grid's number directly because it was a very small benefit. The Company added this "Capacity Savings" benefit to reflect the fact that saving energy all year will result in peak savings as well.

A TOU program will save capacity as well as energy and the Company added this benefit to the list. This benefit is calculated by multiplying the Residential Contribution to System Peak, less EV contribution to peak, by the % energy shift from on-peak to off-peak. The rationale is that if you are moving energy from on-peak hours to off-peak hours, you will also reduce the peak. Again, this benefit calculation was performed on an Opt-In program and an Opt-Out program. These programs have a customer participation rate and a ramp rate/participating customers indicating how long it will take customers to achieve the full savings estimated. The values for these participation rates are assumed to be the same across all the TOU, CPP and TVR programs.

The peak reduction was assumed to be the average of the Low and High values National Grid used in its energy calculation – 3.7% for Opt-In and 2.1% for Opt-Out. The residential contribution to peak (less EVs), in MW, was multiplied by the peak reduction percentages to determine the amount of the system peak that would be reduced. The peak reductions are multiplied by 1,000 to translate MW reductions to kW reductions which are multiplied by the avoided system capacity cost.

The avoided system capacity cost was sourced from the AESC 2021 Report and is expressed in $2021/kW/yr. The values vary from year to year, and they were inflated by 2%/year to determine the system capacity cost in nominal dollars. The annual nominal dollar values are multiplied by the kW peak reductions to determine the annual nominal savings. The annual nominal savings NPV of the benefit. The benefit is also multiplied by 0.99 to reflect the AMF Opt-Out assumption.

The result is a nominal savings of $7.10 million and an NPV of $5.23 million ($2022).

Benefit #30: Benefit from Electromechanical Meter Accuracy – Transfer Payment

As with the Electricity Theft Reduction benefit, this benefit is a transfer payment from customers whose meters are running slowly to those whose meters measure accurately.

Electromechanical meters (EM) tend to "slow down" as they age, registering fewer kWh than are used. AMF meters, because they are digital, do not slow down as they age, ensuring that customers are charged for their full electricity use. This creates additional revenue from customers with older EM meters. In the absence of this revenue, given that the costs reflect the total usage of these customers, the "unpaid" costs from this group of customers must be paid for by all the other customers. If you measure the kWh usage fully, the customers who use the kWh pay for them and the other customers do not. The savings are a "transfer payment" from one set of customers to another and are calculated but not included in the BCA benefits or the B/C ratios.

This benefit is calculated by multiplying the Annual Electromechanical Accuracy Improvement Savings (AEAIS) by .99 due to the AMF 1% Meter Opt-Out to get $6.09 (in millions). The AEAIS was estimated based on the difference in accuracy percentages between the EM meters and the AMF meters, the percentage of time the EM meters are slow (3% of the hours of the year), the number of customers with EM meters, the residential rate ($/kWh), and the average usage of residential customers.

The AEAIS is escalated at 2.30%, the Non-Labor Escalation Rate, to determine the annual nominal value of the Accuracy Improvement Savings. This annual nominal value is multiplied by the Benefit Achievement Rate, which in this case is based on when the current Electromechanical meters would be replaced. The annual nominal values are summed to determine the total nominal benefit and discounted at 6.97% to determine the NPV benefit.

The result is a nominal benefit of $31.47 and an NPV of $17.89 (in millions) ($2022).

Benefit #40: System Capacity Benefit: VVO/CVR

In addition to the 0.5% energy savings attributed to VVO/CVR, there is also a peak savings which is assumed to be 0.167%. The reduction in peak creates additional savings from a system capacity perspective. Rhode Island Energy has VVO/CVR on approximately 10% of its feeders currently, so the Peak values available for the benefit were reduced by 10%. The System Peak was multiplied by 90% to determine the peak MW available for savings and is multiplied by the assumed reduction in peak (0.167%) to determine the peak MW reduced.

The peak MW reduced is multiplied by the Benefit Achievement Rate (BAR) which starts in 2029 at 20% and increases to 100% by 2033 to determine the annual MW reduced.

The annual MW reduced is multiplied by the avoided system capacity costs. The avoided system capacity cost was sourced from the AESC 2021 Report and is expressed in $2021/kW/yr. The values vary from year to year, and they were inflated by 2%/year to determine the system capacity cost in nominal dollars. The annual nominal dollar values are multiplied by the kW peak reductions to determine the annual nominal savings. The annual nominal savings are summed to determine the total nominal benefit and discounted by 2%/year to determine the NPV of the benefit.

The result is a total nominal benefit of $3.07 and an NPV of $2.25 (in millions) ($2022).

Benefit #100: AMR Meter Replacement

Because the bulk of Rhode Island Energy's AMR meters are reaching the end of their design life, they will need to be replaced over the next 5-6 years. If AMF meters are not installed, new AMR meters will need to be installed. These meter and installation costs and many smaller costs associated with AMR meters can be avoided completely by installing AMF meters.

There are two approaches to calculating the benefits of replacing AMR meters with AMF meter. One approach is an incremental approach, wherein the differential between the meter and installation cost is added to costs and not included in the benefits. This would be appropriate if Rhode Island Energy was strictly replacing meters. The Company, however, is proposing a comprehensive program to not only install the meters but to install the communications systems and software to ensure the meter data can flow back to the utility and be used to achieve the benefits laid out in this Business Case.

The second approach, which the Company has adopted, is to include the total costs of the new meters/installation, etc. in the costs and to calculate the avoided costs of replacing the old meters with a new AMR meter. This approach is mathematically equivalent to the incremental approach and will make it easier to track program costs if the program is approved.
This benefit is calculated by determining the number of Residential meters and the number of Commercial meters that will be replaced by AMF meters. The numbers of meters used to calculate the benefits are taken from the Cost Model Inputs and Calcs worksheet which shows the total number of Residential and Commercial meters that will be replaced by AMF meters. The number of meters is allocated out through the years (Benefit Achievement Rate) based on the age of the existing meters and how many would need to be replaced each year.

The costs of the AMR meters were developed by National Grid and adopted by Rhode Island Energy. The costs are in $2020 and escalated by 2.30%/year (Non-Labor Escalation Rate) to determine annual nominal meter cost values. The annual costs/meter are multiplied by the annual number of meters replaced to get an annual avoided cost in nominal dollars. The annual nominal values are summed to determine the total nominal benefit and discounted at 6.97% to determine the NPV benefit.

The result is a total nominal benefit of $50.62 and an NPV of $33.44 (in millions) ($2022).

Benefits #102 and #102.5: Avoided AMR electric meter installation cost – Capex portion and Opex portion

In addition to the capital cost of the meters there are also avoided installation costs. In a more "incremental" analysis, the installation costs could be ignored because both the AMR and AMF meters will need to be installed and the costs are estimated to be the same. As mentioned above, Rhode Island Energy has chosen to include the full cost of AMF meters and installation costs in its overall project cost so that people can easily understand the full impact of the AMF meters and also to make it easier to track the costs of the project as it moves forward (if it is approved.) For this reason, the Company counts as a benefit the full avoided costs of the AMR meters that would need to be replaced.

For Benefits #102 and 102.5, the avoided AMR meter installation cost was calculated and allocated 97% to capital and 3% to O&M. The calculations involve identifying the number of residential and commercial meters that will be installed and reducing them by the 1% AMF meter Opt-Out assumption and multiplying them by the Benefit Achievement Rate (BAR). For these benefits the BAR represents the percent of meters replaced each year and it sums to 100% over the 20-year analysis period. These calculations provided the annual number of meters replaced each year.

The starting installation costs for residential and commercial meters were both taken from the Cost Model developed for this project. They were each inflated by the Labor Escalation Rate of 2.5%/year to develop the annual nominal meter installation costs. The annual nominal meter installation cost is multiplied by the annual number of meters replaced each year and the allocation factor (97% for Capex and 3% for Opex) to develop the annual nominal benefit. The annual nominal values are summed to determine the total nominal benefit and discounted at 6.97% to determine the NPV benefit.

The result for Benefit #102 is a total nominal benefit for the Capex portion is of $16.11 and an NPV of $10.61 (in millions) ($2022). The result for Benefit #102.5 is a total nominal benefit for the Opex portion is $0.50 and an NPV of $0.33 (in millions) ($2022).

Benefit #703 - #705 Non-Embedded NOX, CO2, and Public Health Benefits: VVO/CVR

This benefit is calculated by taking the incremental load reduction due to AMF data in the CVR calculations (MWh) as calculated in Benefit #14 multiplied by the non-embedded NOX average $/MWh multiplied and by the Benefit Achievement Rate (BAR). The BAR begins in 2026 at 20% and increases to 100% at by 2029 and beyond. The calculation also takes into consideration the 1% AMF meter opt out. The avoided non-embedded NOx and the non-embedded CO2 values are sourced from AESC 2021 and is expressed in $2021/MWh. These values are inflated by 2%/year to determine the annual nominal avoided rates. For the Public Health benefit values, the Company used the latest estimates from the EPA and inflated them by 2% to develop the annual nominal avoided public health rates.

The annual nominal avoided rates for NOx, CO2, and Public Health are multiplied by the incremental load reduction from Benefit #14 to determine the annual nominal benefits. The annual nominal values are summed to determine the total nominal benefit and discounted at 3.0% to determine the NPV benefit.

The Non-Embedded NOx benefit is a total nominal benefit of $0.31M and an NPV of $0.24M ($2022).

The Non-Embedded CO2 benefit is a total nominal benefit of $108.78M and an NPV of $81.69M ($2022).

The Public Health benefit is a total nominal benefit of $0.50M and an NPV of $0.37M ($2022).

Benefits #706 - #708 Energy Insights: Non-Embedded NOx &CO2, Public Health

These benefits are calculated by multiplying the reduced consumption (MWh) as calculated in Benefit #16 multiplied by $/MWh values identified for avoided non-embedded NOX, non-embedded CO2, and Public Health benefits. The reduced consumption derivation is described in Benefit #16. It involves a forecast of residential and commercial energy use, Customer Participation Rate (%) for residential and commercial, the anticipated reduction in energy use, the Benefit Achievement Rate, and the AMF meter opt-out rate (1%). These factors are used to determine the annual MWh reductions due to the Energy Insights program.

The avoided non-embedded NOx and CO2 values are sourced from AESC 2021 and are expressed in $2021/MWh. These values are inflated by 2%/year to determine the annual nominal avoided rates. For the Public Health benefit values, the Company used the values that were originally used by National Grid and inflated them by 2% to develop the annual nominal avoided public health rates.

The annual load reductions are multiplied by annual nominal avoided rates for NOx, CO2, and Public Health to determine the annual nominal benefits. The annual nominal values are summed to determine the total nominal benefit and discounted at 2.0% to determine the NPV benefit.

The total nominal benefit for Non-Embedded Nox costs is $0.28M and NPV is $0.22M ($2022).

The total nominal benefit for Non-Embedded CO2 costs is $99.53M and NPV is $74.88M ($2022).

The total nominal benefit for improved Public Health is $0.45M and NPV is $0.34M ($2022).

Benefit #709 Capacity DRIPE Benefit: Whole House CPP

DRIPE = Demand Reduction Induced Price Effect. DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Capacity DRIPE: The change in electricity bills in Rhode Island due to reductions in electric capacity prices.

The DRIPE benefit is developed by multiplying the Opt-In MW by the DRIPE capacity benefit ($). The Opt-In MW reduced that were determined in Benefit #26 are lagged by three years and multiplied by the AESC 2021 Report's DRIPE Capacity Values, which are expressed in $2021/kW-year.

The annual peak MW reductions are multiplied by the avoided DRIPE capacity costs for that year to determine the dollar value of the benefit. The avoided DRIPE capacity costs were sourced from the AESC 2021 Report and are expressed in $2021/kW-year and vary from year to year. The AESC 2021 values were inflated by 2%/year to determine the annual nominal avoided system capacity costs. These annual values were multiplied by the annual peak MW reductions to determine the annual nominal benefit. The annual values were summed to obtain the total nominal dollar savings and then discounted by 2% to determine the NPV of the benefit. The annual values are reduced by the AMF Meter Opt-Out of 1%.

The result is a total nominal benefit of $3.42M and an NPV of $2.48M ($2022).

Benefit #716 – Transmission Capacity Benefit: Whole House CPP

The Transmission Capacity benefit is developed by multiplying the Opt-In MW and the Opt-Out MW reductions by the value of the avoided transmission capacity. The Opt-In and Opt-Out annual MW reductions that were determined in Benefit #26 are multiplied by a transmission coincidence factor (90%) and a transmission success factor (100%) to determine the annual peak MW reductions. The transmission coincidence factor and success factor were developed by National Grid and adopted by Rhode Island Energy.

In the case of avoided transmission, the AESC report included only a single year value of avoided costs - $84.00/kW-year expressed in $2021. To determine the annual values, the 2021 value was escalated at 2%/year. The annual values are reduced by the AMF Meter Opt-Out of 1%.

The annual peak MW reductions are multiplied by the avoided annual capacity costs for that year to determine the annual nominal dollar value of the benefit. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV.
The result is a total nominal benefit of $58.72M opt in and an NPV of $43.25M ($2022).

Benefit #717 – Distribution Capacity Benefit: Whole House CPP

The Distribution Capacity benefit is developed by multiplying the Opt-In MW and the Opt-Out MW reductions by the value of the avoided distribution capacity. The Opt-In and Opt-Out annual MW reductions that were determined in Benefit #26 are multiplied by a distribution coincidence factor (5.8%) and a distribution success factor (100%) to determine the annual peak MW reductions. The distribution coincidence factor and success factor were developed by National Grid and adopted by Rhode Island Energy.

In the case of avoided distribution, the AESC report included only a single year value of avoided costs - $80.24/kW-year expressed in $2021. To determine the annual values, the 2021 value was escalated at 2%/year. The annual values are reduced by the AMF Meter Opt-Out of 1%.

The annual peak MW reductions are multiplied by the avoided annual capacity costs for that year to determine the annual nominal dollar value of the benefit. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV.

The result is a total nominal benefit of $3.40M and an NPV of $2.51M ($2022).

Benefit #718 – Transmission Capacity Benefit: Whole House TOU

The Transmission Capacity benefit for Whole House TOU is developed by multiplying the Opt-In MW and the Opt-Out MW reductions by the value of the avoided transmission capacity. The Opt-In and Opt-Out annual MW reductions that were determined in Benefit #27.5 are multiplied by a transmission coincidence factor (90%) and a transmission success factor (10%) to determine the annual peak MW reductions. The transmission coincidence factor and success factor were developed by National Grid and adopted by Rhode Island Energy.

In the case of avoided transmission, the AESC report included only a single year value of avoided costs - $84.00/kW-year expressed in $2021. To determine the annual values, the 2021 value was escalated at 2%/year. The annual values are reduced by the AMF Meter Opt-Out of 1%.

The annual peak MW reductions are multiplied by the avoided annual capacity costs for that year to determine the annual nominal dollar value of the benefit. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV.

The result is a total nominal benefit of $.97M and an NPV of $.71M opt in ($2022).

Benefit #719 – Distribution Capacity Benefit: Whole House TOU

The Distribution Capacity benefit for Whole House TOU is developed by multiplying the Opt-In MW and the Opt-Out MW reductions by the value of the avoided distribution capacity. The Opt-In and Opt-Out annual MW reductions that were determined in Benefit #27.5 are multiplied by a distribution coincidence factor (5.8%) and a distribution success factor (41.7%) to determine the annual peak MW reductions. The transmission coincidence factor and success factor were developed by National Grid and adopted by Rhode Island Energy.

In the case of avoided transmission, the AESC report included only a single year value of avoided costs - $80.24/kW-year expressed in $2021. To determine the annual values, the 2021 value was escalated at 2%/year. The annual values are reduced by the AMF Meter Opt-Out of 1%.

The result is a total nominal benefit of $0.26M opt in ($2022) and an NPV of $0.19M opt in ($2022).

Benefit #720 – Transmission Capacity Benefit: EV TVR

The Transmission Capacity benefit for EV TVR is developed by multiplying the Opt-In MW and the Opt-Out MW reductions by the value of the avoided transmission capacity. The Opt-In and Opt-Out annual MW reductions (that were determined in the same way that the peak reductions were calculated in Benefit #25) are multiplied by a transmission coincidence factor (90%) to determine the annual peak MW reductions. The transmission coincidence factor was developed by National Grid and adopted by Rhode Island Energy.

In the case of avoided transmission, the AESC report included only a single year value of avoided costs - $84.00/kW-year expressed in $2021. To determine the annual nominal values, the 2021 value was escalated at 2%/year.
The annual nominal savings are derived by multiplying the transmission capacity reductions by the annual nominal costs and are reduced by the AMF Meter Opt-Out of 1%. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV benefit.

The result is a total nominal benefit of $ 58.90M opt in and an NPV of $41.89M opt in ($2022).

Benefit #721 – Distribution Capacity Benefit: EV TVR

The Distribution Capacity benefit for EV TVR is developed by multiplying the Opt-In MW and the Opt-Out MW reductions by the value of the avoided distribution capacity. The Opt-In and Opt-Out annual MW reductions (that were determined in the same way that the peak reductions were calculated in Benefit #25) are multiplied by a distribution coincidence factor (5.8%) to determine the annual peak MW reductions. The distribution coincidence factor was developed by National Grid and adopted by Rhode Island Energy.

In the case of avoided distribution, the AESC report included only a single year value of avoided costs - $80.24/kW-year expressed in $2021. To determine the annual nominal values, the 2021 value was escalated at 2%/year.

The annual nominal savings are derived by multiplying the distribution capacity reductions by the annual nominal costs and are reduced by the AMF Meter Opt-Out of 1%. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV benefit.

The result is a total nominal benefit of $ 3.79M opt in ($2022) and an NPV of $2.70M opt in ($2022).

Benefit #729 – Distribution Capacity Benefit: VVO/CVR

This benefit is calculated by multiplying the lagged capacity reductions developed in Benefit #40 by the distribution coincidence factor (5.8%) to determine the distribution capacity reductions (MW). The distribution coincidence factor was developed by National Grid and adopted by Rhode Island Energy. The distribution capacity reductions are multiplied by the avoided distribution costs.

In the case of avoided distribution, the AESC report included only a single year value of avoided costs - $80.24/kW-year expressed in $2021. To determine the annual nominal values, the 2021 value was escalated at 2%/year.

The annual nominal savings are derived by multiplying the distribution capacity reductions by the annual nominal costs and are reduced by the AMF Meter Opt-Out of 1%. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV benefit.

The result is a total nominal benefit of $0.27M ($2022) and an NPV of $0.20M ($2022).

Benefit #730 – Transmission Capacity Benefit: VVO/CVR

This benefit is calculated by multiplying the lagged capacity reductions developed in Benefit #40 by the transmission coincidence factor (90%) to determine the transmission capacity reductions (MW). The transmission coincidence factor was developed by National Grid and adopted by Rhode Island Energy. The transmission capacity reductions are multiplied by the avoided distribution costs.

In the case of avoided distribution, the AESC report included only a single year value of avoided costs - $80.24/kW-year expressed in $2021. To determine the annual nominal values, the 2021 value was escalated at 2%/year.

The annual nominal savings are derived by multiplying the transmission capacity reductions by the annual nominal costs and are reduced by the AMF Meter Opt-Out of 1%. The annual values are summed to determine the total nominal benefit and discounted by 2% to determine the NPV benefit.

The result is a total nominal benefit of $4.16M ($2022) and an NPV of $3.05M ($2022).

National Grid Benefits Used Directly by Rhode Island Energy

There were numerous benefits calculated by National Grid that were either very small or based on internal National Grid documents. Rather than spend the resources to update them, Rhode Island Energy is submitting the following values that were calculated by National Grid. The total benefits used directly from National Grid total [redacted] Removing these benefits completely would yield a 3.6 nominal B/C ratio and a 3.8 NPV B/C ratio.

[redacted]

[redacted]

[redacted]

Cost Guide: Estimated for Rhode Island Energy AMF Business Case

Introduction

This Cost Guide is intended to be a companion piece to the AMF Benefit-Cost Analysis spreadsheet. This is intended only as an aid to interpreting the calculations of the costs presented in the spreadsheet. All details of the calculations are contained in the Confidential BCA excel file.

Summary of Costs (Nominal and NPV)

AMF Full Deployment Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($M)	CapEx	OpEx
Meters	$ 102.85	$ 79.29	$ 99.67	$ 3.18
Network	$ 27.49	$ 17.03	$ 14.94	$ 12.55
Systems	$ 143.41	$ 79.52	$ 44.66	$ 98.74
Program	$ 15.27	$ 12.14	$ 10.03	$ 5.24
Total AMF Costs	**$ 289.01**	**$ 187.98**	**$ 169.30**	**$ 119.71**

Meters ($102.85m) – *Includes the hardware, scheduling, call center, meter installations, pre-sweeps, sample meter testing, base repairs, and vendor project management costs. Components of this meter category are as follows:*

Meter Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($M)	CapEx	OpEx
Hardware	$ 73.01	$ 55.84	$ 72.85	$ 0.16
Installs	$ 19.03	$ 14.85	$ 19.03	$ -
Pre-Sweeps	$ 4.40	$ 3.52	$ 4.40	$ -
Project Management	$ 3.39	$ 2.73	$ 3.39	$ -
Repairs	$ 3.02	$ 2.35	$ -	$ 3.02
Total Meter Costs	**$ 102.85**	**$ 79.29**	**$ 99.67**	**$ 3.18**

The largest component of Meters is the Hardware, which are the meters themselves along with the shipping and handling, sales tax, testing, and warranty support. Meters are the largest single component of the business case (36%). The total quantity of meters (458,966 Residential and 65,711 Commercial) is based on the total installed electric meter population minus an estimated 1% opt-out rate and 901 meters operating on the MV-90 meter read system. Annual growth rate assumption of 0.25% and failure rate assumption of 0.25% were used. A seed stock estimation of 1.25% Residential and 1.28% Commercial was used based on actual experience. Vendor provided estimates were used for the cost of the meters ([redacted]/unit for residential and [redacted]/unit for commercial).

Additional Hardware costs were included consisting of ancillary devices such as antennas and safety equipment. This ancillary equipment is a small component at $219k. Antennas are anticipated to be needed at 0.5% of the indoor meter locations.

Installation costs ("Installs") account for approximately 18% of the total Meter costs and represent meter installation work including appointment scheduling, meter exchanges/installations, call center, and cross-dock facility costs. Meter installation costs are calculated with the planned assumption that 90% of the work will be performed by a third-party vendor and 10% by internal labor. Installer costs were based on field installer contractor information as well as PPL prior experience with production and efficiency. Calculations were based on a 10-hour day, loaded rate, including vehicle and gas costs. Fully loaded rates were used for both vendor and internal labor. Facility costs represent 22% of total installation costs and cover the costs for a call center, cross-dock warehousing, and shipping verification testing.

Pre-sweep verifications are used to proactively identify meter deployment issues prior to exchanging the meter. Pre-sweeps proved to be a valuable add during the PA AMF deployment. A third-party vendor would be used to perform the pre-sweeps. Pre-sweep cost estimates were based on PA production and efficiency experience, using an average of 54 residential verifications or 36 commercial verifications per day.

Project management costs represent the third-party installation vendor's focused project management efforts during the AMF deployment. The meter vendor project management costs were estimated based on 18% of their total installation efforts. Project management, within this category, accounts for 3% of total meter costs. These estimated costs were based on PPLs experience with their previous AMI implementation. It is our intent to competitively bid installation services.

Repairs capture the costs associated with repairing the meter base at the customer's premise to allow for a new meter installation. Based on PPL's experience, coupled with feedback from Rhode Island Energy field operations, an estimate of 0.5% of the customers' meter bases will need to be repaired to ensure a safe, efficient meter exchange.

Network ($27.49m) – *Includes the communications network needed for secure and reliable communications from the Radio Frequency (RF) meter to the head-end system. Costs of the* *installation of the communications network include the network equipment, installation costs, steady state operations after deployment, and project management costs.*

Network Costs								
As of October 24, 2022					Nominal($M)			
Category	**Nominal ($M)**		**NPV ($M)**		**CapEx**		**OpEx**	
Installs	$	10.76	$	7.22	$	7.18	$	3.58
Steady State Operations	$	8.97	$	3.92	$	-	$	8.97
Hardware	$	6.57	$	4.92	$	6.57	$	-
Project Management	$	1.19	$	0.97	$	1.19	$	-
Total Network Costs	$	27.49	$	17.03	$	14.94	$	12.55

Installation costs ("Installs") include the design, engineering and installation of routers, high-capacity gateways and standard gateways, and other equipment on poles, in cabinets and other locations to enable AMF meters. Network Equipment Installs were based on prior deployment experiences with RF Mesh communications planning, design, and implementation as well as hardware and miscellaneous requirements provided by vendors with support from consultants and PPL's prior experience in PA and KY. It is our intent to competitively bid installation services.

RF Network Hardware ("Hardware") includes routers, high-capacity gateways and standard gateways, cabinets, and other infrastructure required to support the communications network. Costs were based on vendor provided estimates and internal estimates for installations based on previous experiences, along with RI labor cost estimates. The quantity of equipment required for the RF Network was determined by the preliminary RF Design. These include 109 high-capacity gateways (HCC), 402 standard capacity gateways (SCC), and 1,280 routers. A failure rate of .55% was used based on a range between .5-.6% experienced annually in PA across gateways and routers. An upgrade, targeted in 12 years, is an assumed requirement to move fully away from the present day 4G wireless backhaul to 5G (or future available) wireless backhaul option. Additional hardware includes test equipment and ancillary equipment such as cables and analyzers.

Project management cost represents the third-party installation vendor's focused project management efforts during the AMF deployment. The RF vendor project management costs were estimated as 18% of their total installation efforts. Project management, within this category, accounts for 4% of total network costs. These costs were based on vendor feedback and PPLs prior experience.

<u>Systems ($143.41m)</u> – *Includes the Information Technology systems and platforms to enable end to end AMF functionality. The $143.41m consists of:*

Systems Costs				
As of October 24, 2022			Nominal ($M)	
Category	Nominal ($M)	NPV ($M)	CapEx	OpEx
Headend	$ 65.13	$ 34.46	$ 14.52	$ 50.61
MDMS	$ 33.54	$ 16.85	$ 6.86	$ 26.68
Cust Engagement	$ 12.56	$ 7.55	$ 6.67	$ 5.89
Analytics	$ 7.30	$ 4.84	$ 3.78	$ 3.52
Steady State Ops	$ 6.30	$ 2.75	$ -	$ 6.30
Middleware	$ 4.20	$ 2.89	$ 2.76	$ 1.44
ADMS & OMS	$ 2.96	$ 1.99	$ 1.80	$ 1.17
Project Management	$ 2.80	$ 2.30	$ 2.80	$ -
Cyber Security	$ 2.78	$ 2.21	$ 2.58	$ 0.20
CSS	$ 2.71	$ 1.86	$ 1.68	$ 1.03
Grid Edge Comp	$ 1.90	$ 0.82	$ -	$ 1.90
Depl Exchange Mgt	$ 1.22	$ 0.99	$ 1.22	$ -
Total Systems Costs	$ 143.41	$ 79.52	$ 44.67	$ 98.74

Methodology and Basis of Estimation for Systems Costs

PPL followed a stepped process to develop the Systems costs. Step 1 was to review the Systems costs equivalent within the confidential National Grid Updated AMF Business Case excel file. This step provided insights into systems that National Grid considered as part of their AMF deployment as well as the structure of their costs and benefits model. Step 2 was to develop the list of solutions needed to implement and maintain the capabilities based on the functionality roadmap. Step 3, via workshops, gathered feedback on systems implementation, or modification of existing systems, in support of a potential Rhode Island Energy AMF deployment effort. Step 3 resulted in a full listing of requirements for implementation. Step 4 reviewed the list of requirements and estimated design, build, testing, and implementation complexity, timing, and cost. Step 5, carried out in parallel with Step 4, was to incorporate the associated vendor preliminary cost estimates. Step 6 merged the data collected into the cost model. A system integration vendor worked closely with PPL to develop the cost estimation model.

A review of systems costs, by solution, is provided below. Detailed line by line calculations, formulas, and their foundational values can be found within the excel file as part of Appendix H.

Headend - $65.13m – The Rhode Island Energy AMF Headend ("Headend") is separate from the PA AMI Headend instance and is responsible for collecting the meter data from the AMF meters before sending the data downstream. The Rhode Island Energy Headend will be in the vendor cloud and all implementation costs are part of the AMF costs. AMF costs in this category represent:

1) RF Headend costs to standup, integrate, and perform future upgrades are broken down into three components and include planning, design, coding modifications, testing, and implementation:
    a. $10.07m – Headend standup and integrate (years 1-4)
    b. $1.97m – WiSun standup and integrate (years 1-4)
    c. $2.49m - SaaS System Upgrade Testing

    in years 9, 14, and 19 which include a 2.3% BLS ECI Annual adjustment. This was based on historic employment cost index (ECI) data.

2) Annual SaaS fees estimated based on vendor provided estimations:
    a. [redacted] - Headend (years 3-20) calculated at [redacted] with a pro-rated ramp-up amount in the early years and an annual inflation increase of 2.0% starting in year 5, when deployment is completed. The annual inflation is based on historical BLS Core CPI index.
    b. [redacted] – WiSun (years 3-20) calculated at [redacted] with a pro-rated ramp-up amount in the early years and an annual inflation increase of 2.0% starting in year 5, when deployment is completed. The annual inflation is based on historical BLS Core CPI index.

3) Ongoing maintenance and support of the RF Headend SaaS service:
    a. [redacted] – Headend support estimated based [redacted] using the fully loaded labor rate of [redacted] through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
    b. [redacted] – WiSun support estimated based on [redacted] using the fully loaded labor rate of [redacted] through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%

MDMS - $33.54m – The Rhode Island Energy AMF Meter Data Management System (MDMS) is separate from the PA AMI MDMS instance and is responsible for receiving the meter data from the AMF Headend and performing Validation, Estimation, and Editing (VEE) before sending the data downstream. The Rhode Island Energy MDMS will be in the vendor cloud and implementation costs are shared between TSA and AMF costs as detailed in the section below. AMF specific costs in this category represent:

1) MDMS costs to standup, integrate, and perform future upgrades are broken down into two components and include planning, design, coding modifications, testing, and implementation:

   a. $4.44m – MDMS standup and integrate (years 1-4)
   b. $2.42m - SaaS MDMS System Upgrade Testing in years 10 and 16 which include a 2.3% ECI/BLS Annual adjustment

2) Annual SaaS fees estimated based on vendor provided estimations.

3) [redacted] - MDMS (years 3-20) calculated at [redacted] with a pro-rated ramp-up amount during deployment and an annual inflation increase of 2.0% starting in year 5, when deployment is completed. The annual inflation is based on the historical BLS Core CPI index.

4) the ongoing maintenance and support of the MDMS SaaS service
   a. [redacted] – MDMS support estimated based on [redacted] using the fully loaded labor rate of [redacted] through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%

<u>**Customer Engagement**</u> - $12.56m – costs in this category are broken into eight distinct areas.

1) <u>Customer Portal $5.25m</u>
   The Customer Portal system will be the same platform instance utilized by PA. The costs will be allocated between the two operating companies following PPL's cost allocation methodology which is based on customer end points. The split between PA (~1.5 million meters) and Rhode Island Energy (~500k meters) will be approximately 75% PA and 25% RI. Integration modifications between the Customer Portal with the new cloud based MDMS, Headend, and MS Azure Data Lake are captured here. AMF specific costs in this Customer Portal category represent:
   a. $1.08m – integrations estimated based on leveraging existing PA knowledge, processes, and code and includes planning, design, minor coding modifications, testing, and implementation in years 1-4
   b. $4.17m – estimated ongoing maintenance based include:
      - $3.28m [redacted] using the fully loaded labor rate of [redacted] through years 3 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
      - $890k - RIE AMF allocation of the annual PPL website portal operations service of Sitecore Content Management, MS Azure website cloud costs, and Twilio's Sendgrid software. Costs are estimated to start in year 3, go through year 20, and includes an annual increase of .25%, for potential annual customer growth rate.

2) <u>Green Button $664k</u>

   Green Button Connect is functionality that resides on the Customer Portal platform utilized by PA. Rhode Island Energy costs will be allocated following PPL's cost allocation methodology. Coding modification costs within the Green Button Connect functionality and between the new Rhode Island Energy cloud based MDMS are captured here. AMF specific costs in this Green Button Connect functionality category represent:

   a. $664k - integrations estimated based on leveraging existing PA knowledge, processes, and code and include planning, design, minor coding modifications, testing, and implementation in years 1-4

3) <u>Carbon Footprint Calculator $167k</u>

   Carbon Footprint Calculator is functionality that will reside on the Customer Portal platform utilized by PPL. Rhode Island Energy costs will be allocated following PPLs cost allocation methodology. Coding costs for the Carbon Footprint Calculator and integration costs between the new Rhode Island Energy cloud based MDMS are captured here. AMF specific costs in this category represent:

   a. $167k – coding and integrations are estimated based on leveraging existing PA knowledge and code and include planning, design, coding modifications, testing, and implementation in years 1-4

4) <u>Outage Alerts $332k</u>

   Customer Outage Alerts are enabled by functionality that resides on the same alert platform utilized by PA. Rhode Island Energy costs will be allocated following PPL's cost allocation methodology. These costs represent the integration modifications between the alerts platform and the new Rhode Island Energy cloud based MDMS, OMS, CSS, and online portal. AMF specific costs in this Outage Alerts category represent:

   a. $332k - integrations estimated based on leveraging existing PA knowledge, processes, and code and includes planning, design, minor coding modifications, testing, and implementation in years 1-4

5) <u>Bill Alerts $332k</u>

   Customer Bill Alerts are enabled by functionality that resides on the same alerts platform utilized by PA. Rhode Island Energy data will be allocated following PPL's cost allocation methodology. Integration modifications between the alerts platform and the new Rhode Island Energy cloud based MDMS, CSS, and online portal are captured here. AMF specific costs in this Bill Alerts category represent:

a. $332k - integrations estimated based on leveraging existing PA knowledge, processes, and code and includes planning, design, minor coding modifications, testing, and implementation in years 1-4

6) C&I and Multi-Family Portal View $415k

C&I and Multi-Family Portal View are planned to be specialized customer views that would reside on the Customer Portal platform utilized by PPL. Rhode Island Energy costs will be allocated following PPLs cost allocation methodology. Coding for the C&I and Multi-Family Portal View and integrations between MDMS, RF Headend, and CSS are captured here. AMF specific costs in this category represent:

a. $415k - coding and integrations are estimated based on leveraging existing PA knowledge and code and includes planning, design, coding modifications, testing, and implementation in years 1-4

7) Solar Marketplace $664k

Solar Marketplace will be an internally developed PPL solution. The Solar Marketplace offering will utilize the same platform instance as PA and Rhode Island Energy costs will be allocated following PPLs cost allocation methodology. Coding modifications within the Solar Marketplace and integrations with MDMS, and Headend are captured here. AMF specific costs in this Solar Marketplace category represent:

a. $664k - integrations estimated based on leveraging existing PA knowledge, processes, and code and includes planning, design, minor coding modifications, testing, and implementation in years 1-4

8) Time Varying Rates ("TVR") $4.75m

Time Varying Rates ("TVR") is planned to be a vendor developed standalone solution, dedicated for Rhode Island, separate from both MDMS and CSS. The TVR solution would integrate with CSS, MDMS, RF Headend, and Customer Portal. Coding development and associated integrations are captured here. AMF specific costs in this TVR category represent:

a. [redacted] - coding and integrations are estimated based on leveraging existing PA knowledge and code (PA Time of Use) and includes planning, design, coding modifications, testing, and implementation in years 6&7
b. [redacted] - estimated on-going maintenance based on [redacted] Full-Time Equivalent ("FTE") using the fully loaded labor rate of [redacted] through years 8 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%

Analytics - \$7.30m – The Analytics system is the same Microsoft Azure cloud-based solution utilized by PA. Rhode Island Energy costs will be allocated based following PPL's cost allocation methodology. Implementation of that Rhode Island Energy partition and associated analytics integrations with the new Rhode Island Energy cloud based MDMS and Headend are captured below. AMF specific costs in this Analytics category represent:

1) Data Lake implementation, in years 1-4, is broken into three sub-components
    a. \$2.54m – estimated data storage, availability, and transformations including the associated planning, design, coding, testing, and implementation in years 1-4
    b. \$845k – Analytics dashboard creation estimated based on leveraging existing PA knowledge and dashboard code that includes planning, design, coding, testing, and implementation in years 1-4
    c. \$392k - Vendor provided SaaS solutions for Model Validator solutions

2) the ongoing maintenance of the new Analytics AMF integrations and platform
    a. [redacted] – estimated based on [redacted] Full-Time Equivalent ("FTE") to maintain those interfaces and dashboards using the fully loaded labor rate of [redacted] per hour, through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
    b. [redacted] – estimated on-going MS Azure monthly services fees are based on the monthly amount [redacted] prorated based on the fully loaded meter quantities, through years 5 through 20, with an annual meter growth rate of 0.25%
    c. [redacted] – Vendor provided Advanced Grid Analytics (AGA) SaaS fees calculated at [redacted] with a pro-rated ramp-up amount in the initial year and an annual Core CPI index based on BLS of 2.0% in year 5. This vendor provided SaaS service is targeted to be use by end of year 5.

Middleware - \$4.20m – The Middleware software is not a direct 'AMF System' and encompasses several different Middleware software programs in use at PPL. Middleware software acts as "the middleperson" connecting solutions together. Coding needs to be done in all 3 systems involved – the sending system, the middleware, and the receiving system. The Middleware software will be on the same platform instance utilized by PA, with Rhode Island Energy costs to be allocated following PPLs cost allocation methodology. Costs captured here represent the AMF specific coding and on-going maintenance for the Middleware itself. These represent:

1) Middleware costs to develop the AMF specific integrations and execution of critical time-dependent automated routines between AMF systems (Headend, MDMS, WiSun), internal systems (CSS, GIS, ADMS & OMS, Infor, MAM, Azure Data Lake, Customer Portal), and external entities.

   a. $2.76m - coding and integrations are estimated based on leveraging existing PA knowledge, processes, and code and includes planning, design, coding modifications, testing, and implementation in years 1-4

2) the ongoing maintenance and support of the Middleware software and interfaces
   a. [redacted] – Middleware support estimated based on [redacted] using the fully loaded labor rate of [redacted] through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
   b. [redacted] – Rhode Island Energy AMF allocations of the estimated annual PPL Middleware MS Azure costs estimated to start in year 5, go through year 20, and includes an annual increase based on estimated meter population growth (0.25%).

<u>Outage Management System (“OMS”) & Advanced Distribution Management System (“ADMS”)</u> - $2.96m – Both OMS and ADMS, which could also be referenced as basic ADMS, are not direct ‘AMF Systems’. OMS and ADMS costs are listed separately due to the two different solutions used; however, OMS is a component of basic ADMS. Costs specific to both OMS and ADMS are as follows:

1) the new AMF integrations between OMS and ADMS systems are with the RF Headend and MDMS systems.
   a. $1.79m integrations estimated based on leveraging existing PA knowledge and integration code that includes planning, design, testing, and implementation.

2) the ongoing maintenance, in years 5-20, of the new AMF integrations are as follows:
   a. [redacted]– ADMS – estimated based on [redacted]Full-Time Equivalent (“FTE”) to maintain those ongoing interfaces using the fully loaded labor rate assumption [redacted] through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
   b. [redacted] – OMS – estimated based on [redacted] Full-Time Equivalent (“FTE”) to maintain those ongoing interfaces using the fully loaded labor rate assumption of [redacted] through years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
   c. [redacted]– ADMS – estimated based on RIE AMF functionality portion of PPL’s annual GE e-terra Software costs. Costs begin in year 5 and continue through year 20 and include an annual increase based on estimated meter population growth (0.25%).
   d. [redacted]– OMS – estimated based on Rhode Island Energy portion of PPL’s annual GE PowerOn Software. Costs begin in year 5 and continue through year 20 and includes an annual increase based on estimated meter population growth (0.25%).

Project Management - $2.80m – represents the costs of the PPL IT team to provide direct oversight of the system integrator and all the systems efforts that support AMF implementation in years 1-4. There are no IT Program Management costs projected in years 5-20. AMF specific costs in this category represent:

1) Five (5) PPL IT Staff
    a. [redacted] – modeled based on the experience and approach PPL followed for our prior AMI deployment and cost estimated based on five (5) [redacted] dedicated PPL IT staff, through years 1 through 4 with a ramp up starting in Q4 2022. Costs are estimated using the fully loaded labor rate of [redacted] with an annual Cost of Living Adjustment (COLA) of 2.5%
        1. AMF IT Manager
        2. AMF IT System Specialist
        3. AMF IT System Specialist
        4. AMF IT System Specialist
        5. AMF IT System Specialist

Cybersecurity - $2.78m – Cybersecurity costs represent the cybersecurity penetration testing, access reviews, systems reviews, and further integration development costs specific to Rhode Island Energy AMF implementation. AMF specific costs in this category represent:

1) the new development work between Meters, RF Headend, and the MDMS:
    a. $2.58m – coding, integrations, and cybersecurity testing are estimated based on leveraging existing PA knowledge and code (e.g., optical port access alerting) and includes planning, design, coding modifications, testing, and implementation in years 1-4
2) the ongoing maintenance and monitoring of the cybersecurity interfaces
    a. $199k - estimated based on Rhode Island Energy AMF functionality portion of PPL's annual Cybersecurity application costs. Costs begin in year 6 and continue through year 20 and includes an annual increase based on estimated meter population growth (0.25%).

CSS - $2.71m – The Rhode Island Customer Service System ("CSS") will be a separate on-premises instance of the System One CIS. AMF specific costs for CSS are as follows:

1) The new AMF integrations and coding between CSS and the MDMS
    a. $1.68m – coding and integrations estimated based on leveraging existing PA knowledge, processes, and code and includes planning, design, coding modifications, testing, and implementation in years 1-4

2) The ongoing maintenance of the new AMF integrations
    a. [redacted] - estimated on-going maintenance based on [redacted] Full-Time Equivalent ("FTE") using the fully loaded labor rate of [redacted] years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%

Grid Edge & Load Disaggregation - $1.90m – Represents a specific set of functionalities that is enabled by the AMF meters. This is part of the Rhode Island Energy SaaS offering from the AMF Vendor and the method used to estimate these costs aligns with National Grid's methodology.

1) Total Annual SaaS fees
    a. [redacted] - estimated based on [redacted] with an annual meter growth rate of [redacted] Residential adoption estimated at [redacted] of the residential meter population and Commercial adoption estimated at [redacted] of the commercial meter population.

Deployment Exchange Management - $1.22m – Deployment Exchange Management costs represent software and integrations between the Meter Deployment Vendor and Rhode Island Energy to facilitate the daily exchange of customer premise data in support of the meter deployment. Once the deployment is completed this exchange of data is no longer required. These integration costs are specifically between the Deployment Vendor platform with Rhode Island Energy CSS and MDMS. AMF specific costs in this category represent:

1) The new development work between the Deployment Vendor and CSS and MDMS:
    a. [redacted] - coding and integrations are estimated based on leveraging existing PA knowledge, PA past mass deployment processes and code and includes planning, design, coding modifications, testing, and implementation in years 1-4

Steady State Operations - $6.30m – represents the costs of the PPL Business Operations team to operate the AMF system in years 5-20. AMF specific costs in this category represent:

1) [redacted] Rhode Island Energy AMF Business Operations Full-Time Equivalent ("FTE")
    a. [redacted] - estimated based on [redacted] FTE using the [redacted] years 5 through 20, with an annual Cost of Living Adjustment (COLA) of 2.5%
    [redacted]

Program Management ($15.27m) – *Includes project oversight and change management during deployment/implementation and ongoing operations, specifically for change management.*

Program Costs				
	As of October 24, 2022		Nominal ($M)	
Category	Nominal ($M)	NPV ($M)	CapEx	OpEx
Project Management	$ 10.03	$ 8.07	$ 10.03	$ -
Change Management	$ 5.24	$ 4.08	$ -	$ 5.24
Total Program Costs	$ 15.27	$ 12.14	$ 10.03	$ 5.24

Project Management ($10.03m) - Includes dedicated PPL and Rhode Island Energy internal labor directly responsible for implementing the AMF Program. Staffing is based on actual experience implementing AMF in PA.

1. AMF Program Lead
2. Finance and Controls Manager
3. Network Deployment Lead
4. Meter Deployment Lead
5. Meter Deployment Support Project Manager
6. Meter Deployment Support Project Manager
7. Project Manager – Key Initiatives
8. AMF Operations Specialist (Headend System)
9. AMF Operations Specialist (MDMS System)
10. AMF Meter Engineer
11. AMF Meter Testing

[redacted] – The eleven (11) dedicated project management roles were modeled based on previous experience and cost estimated based using a blended fully loaded labor rate of [redacted] through years 2 through 4, with an annual Cost of Living Adjustment (COLA) of 2.5%

In addition, Project Management will be made up of external vendor labor personnel that will support the AMF Program. The eight (8) external vendor labor roles, with estimate loaded hourly rates, to support this work are:

1. Senior Project Manager (at [redacted])
2. Advanced Meter Operations ("AMO") Network Lead (at [redacted])
3. AMO Network Analyst (at [redacted])
4. Metrics, Measures, and Financial Tracking Analyst (at [redacted])
5. Meter & Network Inventory Management Analyst (at [redacted])

6. Deployment Exception Coordinator (at [redacted])
7. Deployment Exception Coordinator (at [redacted])
8. Deployment Exception Coordinator (at [redacted])

[redacted] – The eight (8) vendor project management roles were modeled based on the experience and approach PPL followed for our prior AMI deployment and cost estimated based on the hourly rates noted above, through years 2 through 4

Change Management ($5.24m) – includes PPL internal labor made up of PPL and Rhode Island Energy employees and vendor labor who will lead and be responsible for the Change Management aspects of the AMF Program. Resourcing is based on our experience implementing AMF in PA. The internal team is planned to be made up of [redacted] functioning in the following capacities:

[redacted]

[redacted] - the [redacted] change management roles were estimated based using a blended fully loaded labor rate of [redacted] through years 2 through 7 ([redacted]), with an annual Cost of Living Adjustment (COLA) of 2.5%

Change Management would also include external vendor labor. The [redacted] external vendor labor roles to support this work are:

[redacted]

[redacted] - the [redacted] external change management vendor roles were estimated based on the hourly rates noted above, through years 2 through 4

Lastly, Change Management includes the AMF specific materials (letters, bill inserts, radio ads, local commercials) and trainings related to AMF. Material costs are forecasted starting in year 2 through year 20. Training is forecasted to start in year 3 and end in year 4.

- [redacted] – Materials across years 2-7 ($1.25m) plus across years 8-20 ($116k)
- [redacted] – Training across years 3-4

AMF vs. TSA exit Cost Accounting

A clear distinction has been made between what will be charged to the RI AMF project and what will be included in TSA exit costs. Separate accounting is set up for the two areas to keep costs properly charged. In general, AMF does not include anything that is required for Rhode Island Energy to exit National Grid systems. AMF is related to deploying the new advanced meters and the functionality they enable as defined in our Plan.

Costs and how they will be charged is as follows:

<u>100% AMF costs include</u>:

- Implementation - AMF Headend System to read the new meters is 100% AMF.
- SAAS - annual - RF Headend System would be 100% AMF since only controls RF.

<u>Costs with both AMF and TSA exit components include</u>:

- The MDMS solution is split between TSA exit and AMF. The TSA exit MDMS components include setup and processing of AMR and MV-90 meter reads as well as retail settlement functionality. These activities are considered foundational and included as part of TSA exit efforts. The AMF MDMS functionality includes receiving and processing reads from the new AMF meters. MDMS allocations should be viewed in two sections, Implementation and Ongoing costs.

- MDMS Implementation – based on total number of PPL requirements (224)
    1. Base/AMR – MDMS foundational (match Rhode Island Energy daily read functionality) TSA Exit, 36% based on requirements
    2. Retail Settlement – TSA Exit, 20% based on requirements
    3. RF - 44% AMF based on requirements

- MDMS Ongoing/Annual SaaS cost allocations – based on functionality
    1. AMR – 28% for gas (non-AMF)
    2. Retail Settlement – 20% (non-AMF)
    3. Electric AMF – 52% (AMF)

<u>100% TSA exit costs include:</u>

- Drive-By Meter Reading, MV90 Meter Reading, Wholesale Settlement, and Meter Testing

Comparison between National Grid Top Level AMF Categories and

[redacted]

The above groupings in this chart represent our best estimate of calculating the National Grid costs – Electric Only and comparing to the RIE Costs. Please note that due to the different categories, and costs by category used, these cost estimates for National Grid do not match one for one with the corresponding RIE costs.